COMMONWEALTH OF KENTUCKY
OFFICE OF THE ATTORNEY GENERAL

JACK CONWAY
ATTORNEY GENERAL

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FRANKFORT, KENTUCKY 40601

October 30, 2008

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OCT 30 2008

PUBLIC SERVICE
COMMISSION

Ms. Stephanie Stumbo
Executive Director
Kentucky Public Service Commission
211 Sower Boulevard
Frankfort, KY 40601

Re: Application of Kentucky Utilities Company for an Adjustment of Base Rates
Case No. 2008-00251

Dear Ms. Stumbo:

Please find enclosed for filing in the above referenced case the original and ten (10) copies of the testimony on behalf of the Attorney General.

Please contact our office should you have any questions. Thank you.

Sincerely,

Paul D. Adams
Assistant Attorney General
Office of Rate Intervention

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

RECEIVED

OCT 30 2008

PUBLIC SERVICE
COMMISSION

In the Matter of:

APPLICATION OF KENTUCKY UTILITIES COMPANY FOR AN ADJUSTMENT OF ELECTRIC BASE RATES	)))	**Case No. 2008-00251**

PRE-FILED TESTIMONY ON BEHALF OF THE ATTORNEY GENERAL

Comes now the intervenor, the Attorney General of the Commonwealth of Kentucky, by and through his Office of Rate Intervention, and submits his pre-filed testimony in the above case.

Respectfully submitted,

JACK CONWAY
ATTORNEY GENERAL OF KENTUCKY

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CERTIFICATE OF SERVICE AND NOTICE OF FILING

I hereby give notice that this the 30th day of October, 2008, I have filed the original and ten copies of the foregoing Testimony on Behalf of the Attorney General with the Kentucky Public Service Commission at 211 Sower Boulevard, Frankfort, Kentucky, 40601 and certify that this same day I have served the parties by mailing a true copy of same, postage prepaid, to those listed below.

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COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF KENTUCKY UTIITIES COMPANY FOR AN ADJUSTMENT OF BASE RATES	)))	CASE NO. 2008-00251

DIRECT TESTIMONY

AND EXHIBITS

OF

ROBERT J. HENKES

On Behalf of the Office Of Rate Intervention Of The Attorney General Of The Commonwealth Of Kentucky

October 29, 2008

Kentucky Utilities Company
Case No. 2008-00251
Direct Testimony of Robert J. Henkes

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I. STATEMENT OF QUALIFICATIONS

Q. WOULD YOU STATE YOUR NAME AND ADDRESS?

A. My name is Robert J. Henkes and my business address is 7 Sunset Road, Old Greenwich, Connecticut 06870.

Q. WHAT IS YOUR PRESENT OCCUPATION?

A. I am Principal and founder of Henkes Consulting, a financial consulting firm that specializes in utility regulation.

Q. WHAT IS YOUR REGULATORY EXPERIENCE?

A. I have prepared and presented numerous testimonies in rate proceedings involving electric, gas, telephone, water and wastewater companies in jurisdictions nationwide including Arkansas, Delaware, District of Columbia, Georgia, Kentucky, Maryland, New Jersey, New Mexico, Pennsylvania, Vermont, the U.S. Virgin Islands and before the Federal Energy Regulatory Commission. A complete listing of jurisdictions and rate proceedings in which I have been involved is provided in Appendix I attached to this testimony.

Q. WHAT OTHER PROFESSIONAL EXPERIENCE HAVE YOU HAD?

A. Prior to founding Henkes Consulting in 1999, I was a Principal of The Georgetown Consulting Group, Inc. for over 20 years. At Georgetown Consulting I performed the same type of consulting services as I am currently rendering through Henkes

Consulting. Prior to my association with Georgetown Consulting, I was employed by the American Can Company as Manager of Financial Controls. Before joining the American Can Company, I was employed by the management consulting division of Touche Ross & Company (now Deloitte & Touche) for over six years. At Touche Ross, my experience, in addition to regulatory work, included numerous projects in a wide variety of industries and financial disciplines such as cash flow projections, bonding feasibility, capital and profit forecasting, and the design and implementation of accounting and budgetary reporting and control systems.

Q. WHAT IS YOUR EDUCATIONAL BACKGROUND?

A. I hold a Bachelor degree in Management Science received from the Netherlands School of Business, The Netherlands in 1966; a Bachelor of Arts degree received from the University of Puget Sound, Tacoma, Washington in 1971; and an MBA degree in Finance received from Michigan State University, East Lansing, Michigan in 1973. I have also completed the CPA program of the New York University Graduate School of Business.

II. SCOPE AND PURPOSE OF TESTIMONY

Q. WHAT IS THE SCOPE AND PURPOSE OF THIS TESTIMONY?

A. I was engaged by the Office of Rate Intervention of the Attorney General of Kentucky ("AG") to conduct a review and analysis and present testimony in the matter of the petition of Kentucky Utilities Company ("KU" or the "Company") for an increase in its base rates for electric service.

The purpose of this testimony is to present to the Kentucky Public Service Commission ("KPSC" or the "Commission") the appropriate jurisdictional capitalization and overall rate of return, rate base and pro forma test period operating income, as well as the appropriate jurisdictional electric revenue requirement for the Company in this proceeding.

In the determination of the AG's recommended jurisdictional capitalization and overall rate of return, rate base, operating income and revenue requirement, I have relied on and incorporated the recommendations of the following other expert witnesses engaged by the AG in this proceeding:

1. Dr. J. Randall Woolridge, concerning the appropriate capital structure ratios, cost rates for short- and long term debt, the return on common equity, and the resulting overall rate of return for the Company in this proceeding;
2. Mr. Michael Majoros, concerning the appropriate depreciation rates to be adopted by the Commission in this case; and

3. Mr. Glenn A. Watkins, concerning KU's proposed temperature normalization adjustment.

In developing this testimony, I have reviewed and analyzed the Company's July 29, 2008 filing; supporting testimonies, exhibits, filing requirements and workpapers; the Company's responses to initial and follow-up data requests by the KPSC Staff, AG and other intervenors; and other relevant financial documents and data.

III. SUMMARY OF FINDINGS AND CONCLUSIONS

Q. PLEASE SUMMARIZE YOUR FINDINGS AND CONCLUSIONS IN THIS CASE.

A. I have reached the following findings and conclusions in this case:

1. The revenue requirement determination in this case should be based on KU's jurisdictional capitalization. This revenue requirement determination base has also been proposed by the Company in this rate proceeding and has been consistently applied by the Commission in KU's previous base rate proceedings [Schedule RJH-1, line 1].
2. The appropriate adjusted jurisdictional capitalization as of April 30, 2008, the end of the test period in this case, amounts to $2,052.940 million which is $20.523 million lower than the adjusted jurisdictional capitalization of $2,073.463 million proposed by KU [Schedule RJH-1, line 1 and Schedule RJH-2].
3. The AG's expert rate of return witness, Dr. Woolridge, has at this time recommended a short-term debt cost rate of 2.63%, long-term debt cost rate of 5.21%, and a return on equity of 9.90%. These recommended capital cost rates, together with Dr. Woolridge's recommended capital structure ratios produce the AG's recommended overall rate of return on capitalization for of 7.61%. By comparison, the Company has proposed an overall rate of return on capitalization of 8.31% [Schedule RJH-2].

The recommended rate of return on capitalization of 7.61% is equivalent to a rate of return of 6.96% on the Company's adjusted jurisdictional rate base [Schedule RJH-3, line 15]. The Company has not presented an equivalent proposed overall return on rate base number for its electric operations.

4. The appropriate pro forma adjusted jurisdictional rate base measured as of April 30, 2008, the end of the test period in this case, amounts to $2,243.488 million. The recommended return on rate base amounts to 6.96% [Schedule RJH-3].

5. The appropriate pro forma test period jurisdictional operating income amounts to $181.863 million, which is $23.361 million higher than KU's proposed test period jurisdictional operating income of $158.502 million [Schedule RJH-1, line 4 and schedule RJH-4].

6. The appropriate revenue conversion factor to be used for rate making purposes in this case is .62175222. This factor has been used by both the Company and the AG [Schedule RJH-1, line 6].

7. The application of the recommended overall rate of return of 7.61% to the recommended jurisdictional capitalization of $2,052.940 million, combined with the recommended pro forma test period jurisdictional operating income of $181.863 million and the revenue conversion factor of .62175222 indicates that the Company has an annual revenue *excess* of $41.258 million. This represents a difference of $63.458 million from the Company's proposed annual revenue *deficiency* of $22.200 million [Schedule RJH-1, lines 1-7].

IV. REVENUE REQUIREMENT ISSUES

A. CAPITALIZATION

Q. PLEASE DESCRIBE THE COMPANY'S PROPOSED TEST YEAR-END ADJUSTED CAPITALIZATION FOR ITS ELECTRIC OPERATIONS IN THIS CASE.

A. The Company has proposed an adjusted jurisdictional capitalization of $2,073.463 million. As shown on Rives Exhibit 2, the starting point of the Company's proposed pro forma adjusted jurisdictional capitalization is the actual per books total company capitalization as of 4/30/08 of approximately $2,853.377 million, consisting of short term debt, long term debt, and common equity. The Company then made 3 pro forma jurisdictional capitalization adjustments in order to arrive at its proposed adjusted jurisdictional capitalization of $2,804.251 million. These 3 capitalization adjustments concern (1) the removal of Undistributed Subsidiary Earnings; (2) the removal of KU's investment in EEI; and (3) the removal of KU's investments in Ohio Valley Electric Corporation (OVEC) and other non-utility investments. Next, the Company applied an electric non-ECR rate base ratio of 73.94% to its adjusted jurisdictional capitalization of $2,804.251 million, resulting in its proposed non-ECR jurisdictional capitalization balance of $2,073.463 million.

Q. IS THE METHOD USED BY THE COMPANY IN THE DETERMINATION

OF ITS PROPOSED ADJUSTED CAPITALIZATION CONSISTENT WITH THE METHOD PRESCRIBED BY THE COMMISSION IN THE COMPANY'S PRIOR RATE CASE IN CASE NO. 2003-00434 AND THE RATE CASE BEFORE THAT IN CASE NO. 1998-474?

A. No. The method currently prescribed by the Commission and used in setting KU's rates in its prior two rate cases first calculates the jurisdictional capitalization by multiplying the total company capitalization by a jurisdictional rate base ratio that has *not* first been adjusted by the removal of ECR-related rate base, as the Company has done in the instant rate proceeding. As the next step, the Commission-prescribed method would then remove all ECR-related capital from the jurisdictional-allocated capitalization.

Q. **HAS THE COMPANY PRESENTED THE JURISDICTIONAL-ALLOCATED ADJUSTED CAPITALIZATION AS DETERMINED IN ACCORDANCE WITH THE COMMISSION-PRESCRIBED CALCULATION METHOD?**

A. Yes. The Company has presented the calculations and end-results of the Commission-prescribed methodology in Appendix B of Rives Exhibit 2. As shown in Appendix B, under the Commission-prescribed calculation methodology, the Company's adjusted jurisdictional capitalization amounts to $2,032.391 million as compared to the Company's proposed adjusted jurisdictional capitalization of $2,073.463 million.

Q. WHAT MAKES UP THE DIFFERENCE BETWEEN THE COMMISSION-PRESCRIBED JURISDICTIONAL CAPITALIZATION METHODOLOGY AND THE CALCULATION METHODOLOGY PROPOSED BY THE COMPANY?

A. The difference is that the Commission-prescribed calculation method *does not* recognize the ECR-related deferred income taxes in removing the ECR-related net rate base investment from the jurisdictional capitalization whereas the Company-proposed calculation method in this case *does* recognize ECR-related deferred income taxes in calculating the adjusted jurisdictional capitalization.

Q. HAS THIS DEFERRED TAX ISSUE PREVIOUSLY BEEN ADDRESSED BY THE COMMISSION?

A. Yes. In both Case No. 1998-474 and the instant rate proceeding, the Company has argued that if ECR-related deferred taxes are considered in the determination of the Company's jurisdictional rate base, they should similarly be considered in the determination of the Company's jurisdictional capitalization, otherwise there would not be an accurate reconciliation between the Company's jurisdictional rate base and capitalization. However, the Commission has consistently held that since deferred taxes represent non-investor supplied funds that are not funded by the Company's capitalization, they should not be considered in the determination of the Company's adjusted capitalization. And the Commission has long recognized that a complete reconciliation between a utility's rate base and capitalization may be an appropriate theoretical concept, in practice a utility's rate base is rarely equal to its capitalization. In this regard, the Commission made the following rulings in its Order on Rehearing in LG&E's Case No. 1998-426:

> In its February 9, 2000 Order, the Commission granted rehearing on three issues raised by LG&E: the amount of environmental surcharge [ECR] to be excluded from LG&E's capitalization ....
>
> LG&E argues that the Commission's adjustment to LG&E's capitalization is in error because the adjustment did not recognize Pollution Control Deferred Income Taxes ("PC DIT"). By not recognizing the PC DIT, LG&E claims that the adjustment to its capitalization was excessive and resulted in an overstatement of its revenue sufficiency. LG&E contends that when determining the revenue sufficiency, the exclusion of the environmental surcharge components in base rate calculations should be neutral. To achieve this neutrality, LG&E states that the environmental surcharge amounts removed from its capitalization must be the same as the amounts removed from its rate base. Finally, LG&E takes the position that the April 6, 1995 Order establishing its environmental surcharge equated its environmental surcharge rate base with its environmental surcharge capitalization.
>
> One of the basic theories of rate-making is the concept that a utility's net original cost rate base should be equal to its capitalization. While accepting this theoretical concept, the Commission has long recognized that a utility's rate base is rarely equal to its capitalization....
>
> In determining a utility's revenue requirements, the Commission does not adjust the rate base or capitalization to be equal. Rather, the Commission's Orders state two different rates of return; one on rate base and one on capital. But when the rate base and capital are multiplied by their respective rates of return, they produce the same net operating income found reasonable by the Commission...
>
> The Commission is not persuaded by the evidence or arguments presented by LG&E...
>
> LG&E has acknowledged that the PC DIT are not funded by its capitalization, but are the result of differences between book and tax accounting practices, and requirements prescribed by the applicable tax code...
>
> Therefore, the adjustments to LG&E's rate base and capitalization to remove the impacts of its environmental surcharge will remain as originally calculated in the January 7, 2000 Order.

Q. HAS THE COMPANY IN THE INSTANT PROCEEDING PRESENTED ANY ARGUMENTS THAT ARE DIFFERENT FROM THE ARGUMENTS IT PRESENTED IN CASE NOS. 1998-426 AND 1998-474?

A. No, it has not.

Q. HAS THE COMPANY RECENTLY PRESENTED INFORMATION CLAIMING THAT IT MADE ERRORS IN THE DETERMINATION OF ITS AS-FILED JURISDICTIONAL CAPITALIZATION ON RIVES EXHIBIT 2?

A. Yes. In its response to AG-1-34, the Company stated that it made three errors in the determination of its as-file jurisdictional capitalization on Rives Exhibit 2. First, the Company claims that its proposed as-filed $24.9 million capitalization reduction adjustment for its Investment in EEI is overstated by $23.6 million because this $23.6 million balance represents a double-count with the Undistributed Earnings capitalization reduction adjustment. Thus, the Company claims that the correct capitalization adjustment for its Investment in EEI should be approximately $1.3 million ($24.9 million - $23.6 million). Second, the Company states that the capitalization reduction adjustment balance for its investments in OVEC and other non-utility property should be $.840 million rather than the as-filed balance of $.661 million. And, third, the Company claims that its as-filed capitalization reduction adjustment balance of $23.6 million for its Undistributed Subsidiary Earnings should be reduced by approximately $8.9 million to $14.7 million in order to give recognition to the deferred income taxes associated with the Undistributed Subsidiary Earnings.

Q. DO YOU AGREE WITH THESE THREE ERROR CORRECTIONS CLAIMED BY THE COMPANY?

A. Based on my review of these three issues, I agree with the Company that the first two error corrections should be made. In other words, the as-filed $24.9 million capitalization reduction adjustment for the Company's Investment in EEI should change to an approximate $1.3 million capitalization reduction adjustment, and the as-filed $.661 million capitalization reduction adjustment for the Company's Investment in OVEC/Other should change to a $.840 million capitalization reduction adjustment. However, I disagree with the Company's latest proposal to reduce the Undistributed Subsidiary Earnings capitalization reduction adjustment by $8.9 million by offsetting the earnings balance with the associated deferred income tax balance. This latter proposal is another attempt by the Company to recognize deferred income taxes in the determination of the jurisdictional capitalization and should be rejected by the Commission for the same reasons as previously discussed with regard to the deferred taxes associated with the Company's ECR investments.

Q. COULD YOU NOW DISCUSS YOUR RECOMMENDED ADJUSTED JURISDICTIONAL CAPITALIZATON BALANCE?

A. Yes. Based on the previously discussed findings and conclusions, I recommend that the adjusted jurisdictional capitalization be determined based on the Commission-prescribed calculation method and with the inclusion of the previously described error corrections for the capitalization reduction adjustments for the Investments in EEI and OVEC/Other.

As shown on Schedule RJH-2 at page 2, this results in a recommended adjusted jurisdictional capitalization of $2,052.940 million.

B. RATE OF RETURN ON CAPITALIZATION

Q. PLEASE DESCRIBE THE AG'S RECOMMENDED RATE OF RETURN ON JURISDICTIONAL CAPITALIZATION.

A. As shown on Schedule RJH-2, page 1 of 2, the AG recommends an overall return on capitalization of 7.61% as compared to the Company's proposed overall rate of return number of 8.31%. The AG-recommended overall rate of return number is based on the capital structure ratios and capital cost rates recommended by the AG's rate of return expert, Dr. Woolridge. As shown on Schedule RJH-2, page 1 of 2, Dr. Woolridge recommends a short-term debt cost rate of 2.63%, long-term debt cost rate of 5.21% and a return on equity of 9.90%.

Q. DO YOU AGREE WITH THE COMPANY'S PROPOSAL IN THIS CASE THAT THE COMPANY'S RETURN REQUIREMENT BE DETERMINED

BY APPLYING THE APPROPRIATE OVERALL RATE OF RETURN TO THE ADJUSTED JURISDICTIONAL CAPITALIZATION AT THE END OF THE TEST YEAR?

A. Yes. The Company's proposed return requirement approach in this case is consistent with the return requirement rate making policy adopted by the Commission in all of KU's prior base rate proceedings.

C. RATE BASE AND RETURN ON RATE BASE.

Q. HAS THE COMPANY PRESENTED AN ADJUSTED ORIGINAL COST RATE BASE FOR ITS JURISDICTIONAL OPERATIONS IN ITS FILING SCHEDULES IN THIS PROCEEDING?

A. Yes. As shown on Rives Exhibits 3 and 4, the Company is proposing an adjusted original cost rate base of $2,216.908 million.

Q. HAVE YOU DETERMINED THE APPROPRIATE ADJUSTED ORIGINAL COST RATE BASE FOR KU'S JURISDICTIONAL OPERATIONS IN THIS CASE?

A. Yes, this recommended adjusted jurisdictional original cost rate base has been developed on schedule RJH-3. The starting point is KU's proposed unadjusted jurisdictional original cost rate base of $2,634.974 million measured as of the end of the test year, April 30, 2008. From that starting point, I then removed the

Company's proposed net ECR rate base balance[1] of approximately $415.886 million to arrive at the Company's proposed adjusted jurisdictional rate base balance of $2,219.087 million that excludes all ECR rate base items not rolled into base rates. Finally, I reflected total net rate base additions of $24.400 million to arrive at my recommended adjusted original cost rate base for KU's jurisdictional operations of $2,243.488 million. This recommended adjusted jurisdictional rate base of $2,243.488 million is $26.580 million higher than the Company's proposed adjusted jurisdictional rate base of $2,216.908 million.

Q. WHY IS YOUR RECOMMENDED ADJUSTED ORIGINAL COST RATE BASE $26.580 MILLION HIGHER THAN THE COMPANY'S PROPOSED ORIGINAL COST RATE BASE?

A. As just discussed, I have reflected non-ECR related rate base adjustments that *increase* the rate base by $24.400 million whereas the Company has proposed non-ECR related rate base adjustments that *decrease* the rate base by $2.180 million. This explains why my recommended adjusted rate base is $26.580 million higher than the Company's proposed adjusted rate base. Below, I have listed the component reasons for this rate base differential of $26.580 million:

	KU Rate Base	AG Rate Base	Difference
Depreciation Reserve Adj.	$(.236)	$26.402	$26.638
CWC Adjustment	(1.943)	(2.002)	(.058)
Total	$(2,180)	$24.400	$26.580

As shown in the above table, by far the largest reason for the rate base differential is

[1] Representing the net of the total ECR rate base balance and the ECR rate base balance rolled into base rates.

the pro forma impact on the depreciation reserve resulting from KU's proposal to increase its test year per books depreciation expenses and AG's recommendation to decrease the test year per books depreciation expenses.

Q. PLEASE DISCUSS EACH OF THE RECOMMENDED RATE BASE ADJUSTMENTS TOTALING $24.400 MILLION.

A. The first rate base adjustment of $26.402 million shown on line 2 of the third column of Schedule RJH-3 is a direct result of the AG's recommended annualized depreciation expense adjustment shown on Schedule RJH-8, line 5. This annualized depreciation expense adjustment will be discussed later in this testimony.

The second rate base adjustment of approximately $2 million shown on line 11 of Schedule RJH-3 is to adjust the test year per books cash working capital requirement for the pro forma impact on cash working capital of all of the Company's proposed O&M expense adjustments in this case. In its response to AG-1-12, the Company has acknowledged that the correct cash working capital adjustment resulting from its proposed pro forma O&M expense adjustments should be a reduction of $2.002 million rather than the cash working capital reduction of $1.943 million reflected in the Company's as-filed position. It should be noted that the appropriate cash working capital amount to be reflected for ratemaking purposes in this case should ultimately be based on the reflection of all Commission-ordered pro forma test year electric operation and maintenance expenses allowed in this case.

Q. HAVE YOU CALCULATED THE APPROPRIATE RETURN ON RATE BASE FOR KU'S JURISDICTIONAL OPERATIONS IN THIS CASE?

A. Yes, as shown on Schedule RJH-3, lines 13 through 15, the Company's appropriate return on rate base in this case is 6.96%

D. OPERATING INCOME

Q. PLEASE SUMMARIZE THE COMPANY'S PROPOSED AND YOUR RECOMMENDED PRO FORMA JURISDICTIONAL OPERATING INCOME FOR THE TEST PERIOD IN THIS CASE.

A. The Company's proposed and my recommended pro forma test year jurisdictional operating income positions are summarized on schedule RJH-4. The Company has proposed total pro forma test period jurisdictional operating income of $158.502 million. As summarized on schedule RJH-4, I have made a large number of pro forma operating income adjustments which, in total, have the effect of increasing the Company's proposed test year jurisdictional operating income by $23.361 million to total recommended pro forma test period jurisdictional operating income of $181.863 million. Each of the recommended operating income adjustments will be discussed in detail in the subsequent sections of this testimony.

- **Interest Synchronization**

Q. DOES THE COMMISSON HAVE A RATEMAKING POLICY REGARDING INTEREST SYNCHRONIZATION?

A. Yes. The Commission has a well-established ratemaking policy that the interest expenses to be used as a deduction from pro forma test year taxable income be determined by the application of the weighted cost of debt to the adjusted capitalization allowed by the Commission for ratemaking purposes. This so-called pro forma "synchronized" interest expense level should then replace the per books test year interest expense level that was used as a tax deduction in the determination of the test year income taxes. An income tax adjustment should be made for the difference between the pro forma synchronized interest expenses and the test year per books interest expenses.

Q. IS THERE AN ISSUE IN THE MANNER IN WHICH KU AND THE AG HAVE CALCULATED THEIR RESPECTIVE PRO FORMA SYNCHRONIZED INTEREST EXPENSE LEVELS?

A. No. As shown on schedule RJH-5, both KU and the AG have properly calculated their respective pro forma synchronized interest expense amounts by multiplying their recommended weighted cost of debt percentages included in their overall rate of return numbers times their recommended adjusted capitalization levels. However, since the AG's recommended capitalization and weighted cost of debt numbers are different from those proposed by KU, the AG's recommended synchronized interest level is lower than KU's proposed synchronized interest level.

Q. WHAT IS THE IMPACT OF THESE DIFFERENT SYNCHRONIZED INTEREST LEVELS ON THE COMPANY'S PROPOSED TEST YEAR AFTER-TAX OPERATING INCOME?

A. As shown on Schedule RJH-5, the AG's recommended interest synchronization adjustment decreases the Company's proposed test year after-tax income by $.120 million.

- **Unbilled Revenue Adjustment**

Q. IS THERE AN ISSUE WITH REGARD TO THE COMPANY'S PROPOSAL TO REMOVE UNBILLED ELECTRIC REVENUES FROM THE TEST YEAR?

A. I believe so. The Company has proposed that its unbilled revenues as of April 30, 2008, the end of the test year, be removed and be replaced by the unbilled revenues as of April 2007, the beginning of the test year. Since the unbilled revenues at the end of the test year are $6.878 million higher than the unbilled revenues at the beginning of the test year, the Company's proposed unbilled revenue adjustment increases the base rate revenue requirement and corresponding base rate increase requested in this case by $6,878 million. However, as can be seen from the analysis on Schedule RJH-6, only $6.308 million of the $6.878 million unbilled revenue differential is caused by the difference in unbilled base rate revenues at April 30, 2008 vs. April 30, 2007. Thus, $.570 of the Company's proposed $6.878 million unbilled revenue adjustment is caused by the difference in unbilled FAC, DSM, ECR and other unbilled non-base rate surcharge revenues at April 30, 2008 vs. April 30, 2007. On page 6, lines 1 - 11 of his testimony, Company witness Bellar states that the costs and revenues associated with ratemaking mechanisms such as the fuel adjustment clause, ECR clause or DSM cost recovery should have no effect on the calculation of the base revenue deficiency and corresponding base rate increase that KU is requesting in this case. Yet, this is exactly what the Company is proposing to do through its proposed unbilled revenue adjustment. In summary, I believe it is inappropriate to increase the base rate revenue requirement in this case by $6.878 million if $.570 million of this proposed base rate revenue requirement is caused by the end-of-test year vs. beginning-of-test year differential in unbilled FAC, DSM and ECR surcharge revenues. In addition, the Company has not similarly proposed an adjustment for the differential in the associated end-of-test year vs. beginning-of-test year differential in unbilled FAC, DSM and ECR surcharge costs.

Q. WHAT IS YOUR RECOMMENDATION WITH REGARD TO THIS ISSUE?

A. I recommend that the Company's proposed unbilled revenue adjustment be limited to the unbilled base rate revenues and exclude any unbilled revenue considerations for the FAC, DSM, ECR and other surcharge mechanisms. As shown on Schedule RJH-6, my recommendation would increase the Company's proposed test year after-tax income by $.356 million.

- **Temperature Normalization Adjustment**

Q. PLEASE EXPLAIN THE ADJUSTMENTS THAT YOU HAVE REFLECTED ON SCHEDULE RJH-7 REGARDING THE COMPANY'S PROPOSED TEMPERATURE NORMALIZATION ADJUSTMENT.

A. As shown on Schedule RJH-7, line 1, I have eliminated the Company's proposed electric temperature normalization revenue and associated variable expense reductions based on the recommendations made by AG witness Glenn Watkins with regard to this issue. I should note that if the Commission were to adopt an electric normalization adjustment, there should be an additional expense adjustment in the form of a reduction in PSC assessments and uncollectible expenses. This expense adjustment should be calculated by applying the combined PSC assessment/uncollectible expense rate of .3633% to the amount of the temperature normalization related revenue reduction.

Q. WHAT IS THE IMPACT ON THE COMPANY'S TEST YEAR AFTER-TAX INCOME OF THE DIFFERENCE BETWEEN THE AG'S RECOMMENDED AND THE COMPANY'S PROPOSED TEMPERATURE NORMALIZATION ADJUSTMENTS?

A. As shown on Schedule RJH-7, the difference between the AG's recommended and the Company's proposed temperature normalization adjustments increases the Company's proposed test year after-tax operating income by $2.724 million.

- **Annualized Depreciation Expense**

Q. PLEASE EXPLAIN THE REASON FOR THE RECOMMENDED ANNUALIZED DEPRECIATION EXPENSE ADJUSTMENT SHOWN ON SCHEDULE RJH-8.

A. The annualized depreciation expense adjustment shown on Schedule RJH-8 is a direct result of the difference between the new depreciation rates proposed in this case by KU and those recommended by Michael Majoros, the AG's depreciation expert. The depreciation rates recommended by Mr. Majoros, as applied to the depreciable plant in service balances at the end of the test year, produce $26.638 million lower annualized jurisdictional depreciation expenses than proposed by KU in this case. This has the result of increasing the Company's proposed pro forma test year after-tax jurisdictional operating income by $16.621 million.

- **Correction to Year-End Customer Annualization Adjustment**

Q. WHAT IS THE ISSUE REGARDING THE COMPANY'S PROPOSED YEAR-END CUSTOMER ANNUALIZATION ADJUSTMENT FOR THE SLDEC CUSTOMER CLASS.

A. As shown in the first column on Schedule RJH-9, the test year SLDEC customer count had abnormal customer counts of 5,627 and 20,853 in the months of April and May 2007. As explained in the Company's response to PSC-3-9(b)(c), these abnormal customer counts were caused by a coding error which was corrected in May 2007, resulting in a very large one-time customer count increase. Thus, while the number of SLDEC customers are consistently increasing in every single month of the test year after May 2007, as a result of the abnormal one-time customer spike of 20,853 in May, the year-end customer annualization adjustment methodology produces the erroneous conclusion that the customer count for SLDEC is decreasing.

Q. WHAT ADJUSTMENT DO YOU RECOMMEND TO RECTIFY THIS ERRONEOUS END RESULT?

A. As shown in the last column of Schedule RJH-9, I have replaced the abnormal April and May 2007 customer levels with estimated normalized customer counts that would fit the customer growth trend experienced in the remaining months of the test year.

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDATION ON THE COMPANY'S TEST YEAR JURSIDICTONAL AFTER-TAX INCOME?

A. As shown on Schedule RJH-9, lines 5 – 9, my recommendation increases the Company's proposed test year jurisdictional after-tax operating income by approximately $29,000.

- **Labor Cost Adjustment**

Q. PLEASE EXPLAIN THE REASON FOR THE RECOMMENDED LABOR COST ADJUSTMENT SHOWN ON SCHEDULE RJH-10.

A. The recommended labor cost adjustment consists of two parts. The first part represents a labor cost adjustment of $.224 million to correct for an error in the Company's as-filed labor cost adjustment calculations. The second part represents a labor cost adjustment of $.192 million to remove certain executive incentive compensation expenses from the test year electric operating expenses.

As shown on schedule RJH-10, the recommended total labor cost adjustment increases the Company's proposed test year jurisdictional after-tax operating income by approximately $.260 million.

- **Employee Benefit Cost Adjustment**

Q. PLEASE EXPLAIN THE REASON FOR THE RECOMMENDED EMPLOYEE BENEFIT COST ADJUSTMENT SHOWN ON SCHEDULE RJH-11.

A. The recommended jurisdictional employee benefit cost adjustment total of $.340 million results from corrections made by the Company in its as-filed cost adjustments for pension, OPEB and Post-Employment Benefit expenses.

As shown on schedule RJH-11, the recommended total employee benefit cost adjustment increases the Company's proposed test year jurisdictional after-tax operating income by approximately $.189 million.

- **Ice Storm Amortization Expense Adjustment**

Q. WHAT IS THE ISSUE WITH REGARD TO THE ICE STORM AMORTIZATION EXPENSE ADDRESSED ON SCHEDULE RJH-12?

A. As shown in the responses to AG-1-7 and AG-1-36, the test year includes approximately $.792 million worth of Ice Storm amortization expenses which will no longer be booked as of June 30, 2009 because at that date this deferred cost will be fully amortized. What this means is that this $.792 million expense will cease to be incurred about 5 months after the expected rate effective date of February 6, 2009.[2]

Q. DO YOU RECOMMEND AN ADJUSTMENT TO PROPERLY ADDRESS THIS ISSUE?

A. Yes. As shown on Schedule RJH-12, line 3, the unamortized cost balance as of the rate effective date of this case, February 6, 2009, will be approximately $330,000. I recommend that this unamortized cost balance be re-amortized over a three-year period, resulting in an annual amortization expense of $.110 million. Compared to the actual test year amortization expense of $.792 million, my recommendation reduces the Company's proposed jurisdictional test year expenses by $.682 million.

[2] See the Company's response to AG-1-38.

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDATION ON THE COMPANY'S TEST YEAR JURSIDICTONAL AFTER-TAX INCOME?

A. As shown on Schedule RJH-12, lines 7 – 9, my recommendation increases the Company's proposed test year jurisdictional after-tax operating income by $.426 million.

- **MISO Net Expense Adjustment**

Q. WHAT IS THE HISTORY OF THE NET MISO COST ISSUE IN THIS CASE?

A. In its May 31, 2006 Order in Case No. 2003-00266, the Commission authorized KU to exit the Midwest Independent Transmission System Operator ("MISO"). The Order further prescribed the following accounting treatment for the MISO exit fee and the MISO Schedule 10 fees then and currently embedded in the Company's base rates:

> [T]he Commission concludes that it is reasonable to establish a regulatory asset for the actual amount of the exit fee, subject to adjustment for future MISO credits, if any, and a regulatory liability for the MISO Schedule 10 charges, which are the only MISO costs now included in existing rates. This accounting treatment will have no immediate impact on LG&E's and KU's rates as it defers the rate-making disposition of these amounts until subsequent base rate cases.

In the instant proceeding, KU has presented its proposed ratemaking treatment for this issue.

Q. WHAT IS THE COMPANY'S PROPOSED RATEMAKING TREATMENT OF THIS ISSUE?

A. The Company's actual jurisdictional regulatory asset balance for the MISO exit fees at the end of the test year, 4/30/08, amounts to approximately $16.362 million. The Company's actual regulatory liability balance for its cumulative MISO Schedule 10 rate collections at the end of the test year amounts to approximately $6.552 million. As shown on Reference Schedule 1.23, the Company is proposing to amortize the jurisdictional net MISO cost balance of approximately $9.810 million over a 5-year period for a proposed annual amortization expense of approximately $1.962 million. The Company further proposes that the continuing MISO Schedule 10 rate collections and MISO exit fee credits booked between 4/30/08 and the rate effective date of the instant rate case be deferred as regulatory liabilities for rate recognition in the Company's next base rate case.

Q. DO YOU AGREE WITH THIS RATEMAKING PROPOSAL FOR THE NET MISO COSTS?

A. I agree with the Company's proposal to amortize the net balance of the MISO exit fees and cumulative MISO Schedule 10 collections over a 5-year period. However, I do not agree with the Company's proposal to limit the amortization to the actual balances existing at the end of the test year while leaving the rate recognition for continuing post-test year MISO exit fee credits and MISO Schedule 10 collections until the next base rate case.

Q. WHAT RATE TREATMENT DO YOU RECOMMEND FOR THIS ISSUE?

A. At a minimum, the rate recognition for this issue in this case should include the continuing MISO exit fee credits and MISO Schedule 10 collections from the end of the test year until the expected February 6, 2009 rate effective date of this rate case. As shown on Schedule RJH-13, line 9, the recognition of these post-test year MISO exit fee credits and MISO Schedule 10 rate collections would result in a 5-year net MISO cost amortization of $1.322 million as opposed to the Company's proposed net MISO cost amortization of $1.962 million based on the actual balances at the end of the test year.

In addition, the Company has provided information showing expected MISO exit fee credits of $2.112 million during the approximate 6-year period from the rate effective date in this case until the first quarter of the year 2015. This would equate to an average annual MISO exit fee credit of $.352 million. It is my recommendation that this average annual exit fee credit be recognized for ratemaking purposes as well. As shown on Schedule RJH-13, line 15, this would result in a recommended annual net MISO cost amortization of $.970 million.

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDATION ON THE COMPANY'S TEST YEAR AFTER-TAX INCOME?

A. As shown on Schedule RJH-13, lines 15 - 19, the difference between my recommended annual net MISO cost amortization of $.970 million and the Company's proposed annual net MISO cost amortization of $1.962 million increases the Company's test year after-tax income by $.619 million.

- **New Bank Credit Facilities Adjustment**

Q. HAVE YOU MADE AN ADJUSTMENT TO THE COMPANY'S PROPOSED ADJUSTMENT FOR THE NEW BANK CHARGE CREDIT FACILITY CHARGES?

A. Yes. As shown on Schedule RJH-14, the Company has proposed an expense adjustment of $2.250 million for this item. This proposed cost amount assumes letters of credit associated with three anticipated bond issues totaling $200 million, an estimate letter of credit fee of 1.1%, and associated annual recurring legal fees of $50,000. None of these assumptions are firm at this time. For example, in its response to AG-2-20, the Company changed the amount of the anticipated bond issues from $200 million to $194.847 million and stated:

> The company currently expects to close on the $77.9 million bond during October 2008, the $50 million bond and the $12.9 million bond in November 2008, and the $54 million bond in late November or December 2008. However, the capital markets are extremely volatile and market conditions may result in the need to modify this plan.

The letter of credit fees are also uncertain at this time. While the Company initially assumed an annual fee of 1.1% of the total bond issuance amount, in September 2008 it revised the estimated annual fee to .5% and most recently revised it again to a rate of .7%. The Company has also provided no support for the legal expense of $50,000 and has not clarified that this is an annual recurring expense. For these reasons, I do not believe that the expense adjustment amount proposed by the

Company in this case is known and measurable at this time.

Q. WHAT IS YOUR RECOMMENDATION WITH REGARD TO THIS ISSUE BASED ON THE FOREGOING FINDINGS AND CONCLUSIONS?

A. I have decided to take a conservative position on this matter. Specifically, rather than rejecting the Company's proposed expense adjustment for the reason that it is not known and measurable at this time, I have assumed the updated, revised total bond issuance amount of $194.847 million, the most recent available letter of credit fee of .7% and the same $50,000 annual legal fees proposed by the Company. As shown on Schedule RJH-14, based on these conservative assumptions, my recommendation at this time is to reflect a pro forma expense adjustment of $1.414 million on a total company basis. This recommended expense adjustment should be updated when firm, actual information has become available regarding the amount and timing of the bond issuances, the letter of credit percentage fee, and the annual recurring legal fees prior to the close of record in this case.

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDATIONS REGARDING THIS ISSUE ON THE COMPANY'S PROPOSED TEST YEAR AFTER-TAX JURISDICTIONAL OPERATING INCOME?

A. As shown on Schedule RJH-14, my recommendations regarding this issue increase the Company's proposed test year after-tax jurisdictional operating income by $.465 million.

- **Kentucky Coal Credit Adjustment**

Q. HAS THE COMPANY MADE AN ADJUSTMENT TO REMOVE KENTUCKY COAL TAX CREDITS FROM ITS TEST YEAR PROPERTY TAXES?

A. Yes. As shown on Reference Schedule 1.33, the Company has removed $447,054 worth of Kentucky coal tax credits from its test year jurisdictional property taxes.

Q. WHY HAS THE COMPANY MADE THIS ADJUSTMENT?

A. The reason for the Company's proposed adjustment is explained on pages 6-7 of Ms. Scott's testimony:

> This adjustment is to remove the Kentucky coal tax credit received by the Company during the test year and applied to property taxes. The coal tax credit was established by Kentucky Revised Statute 141.0405 and is contingent on the Company's annual level of Kentucky coal purchases versus the 1999 baseline level of purchases. The Company must apply for the credit annually and, if approved, the coal tax credit must be applied first to income taxes, and any remaining credit may be applied to property taxes. The coal tax credit statute expires in 2009. Due to its upcoming expiration and its contingent nature, the credit is not fixed, cannot be considered to be an on-going reduction to property tax expenses, and is removed from the test year.

Q. DO YOU AGREE WITH THE COMPANY THAT THE KENTUCKY COAL TAX CREDIT SHOULD BE REMOVED FROM THE TEST YEAR IN THIS CASE BECAUSE IT EXPIRES IN 2009?

A. No. As confirmed in its response to AG-2-9, if the Company generates coal tax credits from coal purchases in 2008 and 2009, the tax credits will be available as property tax or income tax credits in calendar years 2009 and 2010. The Company has acknowledged that, if applicable, it will apply for these future coal tax credits.[3] In addition, with the anticipation of another rate case in conjunction with Trimble County Unit 2 going into service in the summer of 2010, there should be no concern that the rate recognition of potential coal tax credits through December 2010 will have a negative financial impact on KU.

Q. DO YOU AGREE WITH THE COMPANY THAT THE KENTUCKY COAL TAX CREDIT SHOULD BE REMOVED FROM THE TEST YEAR IN THIS CASE BECAUSE OF ITS CONTINGENT NATURE?

A. No. As confirmed in the response to PSC-2-116, KU has qualified for the coal tax credit in each of the last five years, 2003 through 2007. Based on this history, I believe it is unreasonable to assume that the Company's ability to utilize these tax credits will suddenly cease in the years 2009 and 2010.

Q. BASED ON THE FOREGOING FINDINGS AND CONCLUSIONS, WHAT RATEMAKING TREATMENT ARE YOU RECOMMENDING FOR THIS ISSUE IN THIS CASE?

A. I recommend rate recognition of a normalized annual Kentucky coal tax credit amount based on the average of the actual coal tax credits experienced by the Company in the most recent 5-year period. As shown in Schedule RJH-15, this

[3] Response to PSC-2-118(d).

results in a recommended normalized annual coal tax credit amount of $.700 million. To be conservative,[4] I also recommend that this coal tax credit be reflected as a property tax credit rather than as a Kentucky income tax credit.

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDATION ON THE COMPANY'S TEST YEAR JURISDICTIONAL AFTER-TAX OPERATING INCOME?

A. As shown on Schedule RJH-15, my recommendation increases the Company's test year jurisdictional after-tax operating income by $.384 million.

- **Normalized Legal Expense Adjustment**

Q. WHAT IS THE ISSUE WITH REGARD TO THE COMPANY'S TEST YEAR LEGAL EXPENSES?

A. I believe that the test year legal expenses are abnormally high and recommend that they be normalized to a more reasonable level. Below, I have listed the actual total company legal expenses booked by the Company during the last 5 years, including the test year:

2004	$3.145 million
2005	4.192 million
2006	3.585 million
2007	4.902 million
Test Year	6.110 million

[4] As shown on Schedule RJH-15, treating the tax credit as a property tax credit will increase the Company's jurisdictional after-tax income by $384,000. Based on the response to AG-2-9(e), Mr. Henkes is of the understanding that if the tax credit would be used as a Kentucky income tax credit, it would increase the Company's jurisdictional after-tax income by $400,000 ($700,000 x 88.038% x 65%).

As evidenced from the above table, the Company's legal expenses can fluctuate upwards and downwards each year depending on the various legal issues that can materialize each year. Based on this evidence, I believe it is more appropriate to normalize the actual test year legal expenses based on an inflation-adjusted average historic legal expense experience.

Q. PLEASE DESCRIBE THE DERIVATION OF YOUR RECOMMENDED NORMALIZED TEST YEAR LEGAL EXPENSE LEVEL.

A. This is shown on Schedule RJH-16. I first inflated the actual legal expenses booked by the Company in the years 2004 through the test year at the CPI – All Urban Consumers Inflator and then took the 5-year average of these inflated annual legal expenses. This produced an inflated average legal expense level of $4.564 million. I then rounded this average expense level up to $4.6 million in order to arrive at my recommended normalized test year legal expense level on a total company basis. It should be noted that this normalized legal expense level is approximately 7% higher than the Company's total company budgeted legal expenses included in its Board-approved 2008 operating budget.

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDATION ON THE COMPANY'S TEST YEAR JURISDICTIONAL AFTER-TAX OPERATING INCOME?

A. As shown on Schedule RJH-16, my recommendation increases the Company's test year jurisdictional after-tax operating income by $.840 million.

- **Normalized Uncollectible Expense Adjustment**

Q. WHAT IS THE ISSUE WITH REGARD TO THE COMPANY'S TEST YEAR UNCOLLECTIBLE EXPENSES?

A. I believe that the test year uncollectible expenses are abnormally high and recommend that they be normalized to a more reasonable level. Below, I have listed the actual total company uncollectible expenses booked by the Company during the last 4 years, including the test year:

2005	2.339 million
2006	2.609 million
2007	2.324 million
Test Year	3.331 million

As evidenced from the above table, the Company's actual test year uncollectible expenses are substantially higher than the uncollectible expenses in the years 2005 through 2007. The Company's response to PSC-2-132(n) states that approximately $.7 million of the large increase in the test year uncollectible expenses is the result of a billing dispute with Owensboro Municipal Authority. In its response to AG-2-28(a) and (b), the Company further clarifies that:

> (a) The litigation between KU and Owensboro Municipal Utilities (OMU) involves a number of issues, including a billing dispute regarding the pricing of back-up power provided to OMU by KU when OMU's own generating units are unable to supply the needs of OMU's customers. The litigation was initially filed by OMU and the City of Owensboro in 2004, although the referenced billing dispute preceded that actual filing by several years. Trial is scheduled to begin on October 14, 2008, and could last several weeks or more. Still, a date for final resolution of the dispute

is unknown, as all substantive rulings to date remain subject to appeal. KU has defended, and expects to continue to vigorously defend itself against OMU's claims and prosecute KU's claims against OMU.

(b) The test year expense for Account 904 would have been $2,564,027 without the expenses associated with the Owensboro billing dispute.

Based on the above information, I believe that the appropriate normalized test year uncollectible expenses should exclude the approximate $.767 million[5] uncollectible expense portion that relates to the OMU billing dispute. From what I understand, while this $.767 million uncollectible portion is currently in dispute, it does not represent an actual charge-off at this time and is not representative of the Company's normal, ongoing uncollectible accrual experience.

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDATION ON THE COMPANY'S TEST YEAR JURISDICTIONAL AFTER-TAX OPERATING INCOME?

A. As shown on Schedule RJH-17, my recommendation increases the Company's test year jurisdictional after-tax operating income by $.450 million.

- **EEI Dues Adjustment**

Q. PLEASE EXPLAIN YOUR RECOMMENDATION TO REMOVE A PORTION OF THE COMPANY'S ANNUAL EDISON ELECTRIC INSTITUTE (EEI) DUES FOR RATEMAKING PURPOSES IN THIS CASE.

[5] Actual test year uncollectible expenses of $3.331 million less uncollectible expenses of $2.564 million exclusive of billing dispute expenses indicates billing dispute expenses of $ 767 million.

A. The test year electric operating expenses include $.378 million for total company EEI dues. Certain portions of EEI activities are dedicated to legislative advocacy, regulatory advocacy and public relations which are forms of lobbying activities, as determined by the Commission in KU's prior rate case, Case No. 2003-00434. In the prior case, NARUC information was available that identified that 45.35% of EEI's activities accounted for legislative/regulatory advocacy and public relations and, based on that information, the Commission ruled that 45.35% of the Company's EEI dues in that case be disallowed for ratemaking purposes.[6] In its response to AG-1-65 in the current case, the Company has indicated that EEI is no longer preparing the same breakout of activities by NARUC category as provided in the prior case, but that for 2007, EEI determined that 16.15% of 2007 dues was spent on lobbying activities. It is not known whether EEI's determination of what represents lobbying activities is as inclusive as, and exactly similar to, NARUC's classification of EEI's legislative and regulatory advocacy and public relations activities. I have therefore relied on the same 45.35% EEI lobbying expense ratio as established by the Commission in the prior case in my determination of the EEI dues to be excluded for ratemaking purposes in the current case.

As shown on Schedule RJH-18, the application of the lobbying ratio of 45.35% to the test year total company EEI dues of $.378 million indicates a disallowed total company expense amount of $.171 million. This expense amount should be the responsibility of KU's stockholders as they produce no benefits to the Company's

[6] See pages 44-45 of the PSC Order in Case No. 2003-00434.

ratepayers.

As shown on Schedule RJH-18, my recommendation increases the Company's proposed test year jurisdictional after-tax operating income by approximately $95,000.

- **Miscellaneous Expense Adjustments**

Q. PLEASE DESCRIBE THE MISCELLANEOUS ADJUSTMENTS SHOWN ON SCHEDULE RJH-19.

A. First, I recommend the removal from test year jurisdictional operating expenses of $14,000 for expenses associated with employee gifts, award banquets, parties and other social events (e.g., company picnics). My recommendation is consistent with previously established Commission-policy that such expenses do not produce benefits to the ratepayers and should be excluded for ratemaking purposes.[7]

Second, I recommend the removal from test year jurisdictional operating expenses of approximately $4,000 worth of penalty and fines expenses. Such expenses should be funded by the Company's stockholders, not ratepayers.

Third, I have removed $18,000 of jurisdictional operating expenses associated with

[7] Similar expenses were excluded from rate recognition in the Company's prior rate case – see pages 43-44 in the PSC Order in Case No. 2003-00434.

real estate receptions and community involvement. As shown in more detail in the responses to AG-2-21 and 2-22, these expenses are for such items as community trade shows, fundraisers, music, florists, showcase gifts, reception catering, valet parking, service charges, etc. I do not believe that such expenses should be funded by the ratepayers as they have nothing to do with the provision of safe, adequate and reliable electric service.

Q. WHAT IS THE IMPACT OF YOUR MISCELLANEOUS EXPENSE ADJUSTMENT RECOMMENDATIONS ON THE COMPANY'S PROPOSED TEST YEAR JURSDICTIONAL AFTER-TAX OPERATING INCOME?

A. As shown on schedule RJH-19, the recommended miscellaneous expense adjustments increase the Company's proposed test year jurisdictional after-tax operating income by approximately $22,000.

- **Hurricane Ike Storm Damage Expenses**

Q. DO YOU HAVE ANY COMMENTS ON THE COMPANY'S RECENT CORRESPONDENCE REGARDING STORM DAMAGE EXPENSES INCURRED DUE TO HURRICANE IKE?

A. Yes. In its updated 10/23/08 response to PSC-1-43, the Company reported that it recently incurred extraordinary and material damage to its distribution, transmission and other facilities as a result of hurricane Ike. The response further stated with regard to this issue that:

> No later than Tuesday, October 28, 2008, the Companies will file applications to initiate separate proceedings to seek orders from the Commission to approve the establishment of regulatory assets to accumulate and defer for future recovery the Companies' costs incurred due to Hurricane Ike. If the Commission grants the Companies' requested relief in those separate proceedings, the Companies anticipate asking the Commission in these base rate proceedings for amortization and base rate recovery of the Hurricane Ike regulatory assets.

Since the Company filed this application during the time of this writing, October 29, 2008, the AG cannot take a position on this matter at this time. However, the AG will address this matter at the appropriate time after all discovery, review and analyses of this issue in the Company's October 27, 2008 application have been completed.

Q. MR. HENKES, DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

KENTUCKY UTILITIES COMPANY
REVENUE REQUIREMENT
($000)

	KU Jurisdictional (1)	Adjustments	AG	
1. Capital Structure	$ 2,073,463	$ (20,523)	$ 2,052,940	Sch. RJH-2
2. Rate of Return	8.31%		7.61%	Sch. RJH-2
3. Income Requirement	172,305		156,211	
4. Pro Forma Income	158,502	23,361	181,863	Sch. RJH-4
5. Income Deficiency	13,803		(25,652)	
6. Revenue Conversion Factor	0.62175222		0.62175222	
7. Overall Revenue Deficiency	$ 22,200	$ (63,458)	$ (41,258)	

(1) Rives Exhibit 8, page 1

KENTUCKY UTILITIES COMPANY
ADJUSTED CAPITALIZATION AT 4/30/08
($000)

KU PROPOSED:	Adjusted Capitalization (1)	Capitalization Ratios	Cost Rates	Weighted Cost Rates
1. Short Term Debt	$ 56,027	2.70%	2.63%	0.07%
2. Long Term Debt	926,166	44.67%	5.21%	2.33%
3. Common Equity	1,091,270	52.63%	11.25%	5.92%
4. Total	$ 2,073,463	100.00%		8.31%

AG RECOMMENDED:	Adjusted Capitalization (2)	Capitalization Ratios	Cost Rates (3)	Weighted Cost Rates
1. Short Term Debt	$ 55,598	2.70%	2.63%	0.07%
2. Long Term Debt	916,790	44.67%	5.21%	2.33%
3. Common Equity	1,080,552	52.63%	9.90%	5.21%
4. Total	$ 2,052,940	100.00%		7.61%

(1) Rives Exhibit 2, page 1
(2) Schedule RJH-2, page 2 of 2, lines 1. 2 and 3
(3) Testimony of J. Randall Woolridge

KENTUCKY UTILITIES COMPANY
AG's RECOMMENDED CAPITALIZATION
($000)

	Capitalization Adjusted for Reacq. Bonds	Undistr. Subsidiary Earnings	Investment in EEI	Investm. in OVEC/Other	Total Adjusted Capitalization	Rate Base Ratio	Kentucky Jurisdictional Capitalization
	(1)	(1)	(2)	(2)		(1)	
1. ST Debt	76,609		(43)	(27)	76,539	87.80%	67,201
2. LT Debt	1,263,753		(566)	(367)	1,262,820	87.80%	1,108,756
3. Equity	1,513,015	(23,585)	(687)	(446)	1,488,297	87.80%	1,306,725
4. Total	2,853,377	(23,585)	(1,296)	(840)	2,827,656		2,482,682

	Kentucky Jurisdict. Capitalization	ECR	Adjusted Kentucky Jurisdict. Capitalization
		(1)	
5. ST Debt	67,201	(11,603)	55,598
6. LT Debt	1,108,756	(191,966)	916,790
7. Equity	1,306,725	(226,173)	1,080,552
8. Total	2,482,682	(429,742)	2,052,940

(1) Rives Appendix B - Exhibit 2, page 1 of 2
(2) Rives Appendix B - Exhibit 2, page 1 cols. (5) and (6), corrected for double-count in EEI Investment and additional removal of non-utility property

KENTUCKY UTILITIES COMPANY
RETURN ON ORIGINAL COST RATE BASE
($000)

	KU Jurisdictional (1)	Remove Net ECR (1)	Other Adjustments		AG	
1. Utility Plant at Original Cost	$ 4,495,694	$ (440,496)			$ 4,055,198	
2. Reserve for Depreciation	(1,707,656)	10,275	26,402	(2)	(1,670,979)	
3. Net Utility Plant	2,788,038	(430,221)	26,402		2,384,219	
Deduct:						
4. Customer Advances	(2,406)				(2,406)	
5. Deferred Income Taxes	(256,897)	3,919			(252,978)	
6. Investment Tax Credit	(49,714)	9,936			(39,778)	
7. Net ARO Assets	931				931	
8. Total Deductions	(308,086)	13,855			(294,231)	
Add:						
9. Materials and Supplies	74,430	(268)			74,162	
10. Prepayments & Allowances	1,654	981			2,635	
11. Cash Working Capital	78,938	(233)	(2,002)	(3)	76,703	
12. Total Additions	155,022	480	(2,002)		153,500	
13. Total Net Original Rate Base	$ 2,634,974	$ (415,886)	$ 24,400		$ 2,243,488	
14. Income Requirement					$ 156,211	Sch. RJH-1, L3
15. Return on Rate Base [L14 / L13]					6.96%	

(1) Rives Exhibit 3, page 1
(2) Impact on depreciation reserve of AG's recommended depreciation expense adjustment - see Schedule RJH-8, L5
(3) Per response to AG-1-12: corrected CWC adjustment should be a decrease of $2,002,080

KENTUCKY UTILITIES COMPANY
PRO FORMA OPERATING INCOME
($000)

	KU Jurisdictional	
1. KU's Proposed Pro Forma After-Tax Operating Income:	$ 158,502	Rives Exh. 1, p.3
AG-RECOMMENDED ADJUSTMENTS:		
2. Interest Synchonization	(120)	Sch. RJH-5
3. Unbilled Revenue Adjustment	356	Sch. RJH-6
4. Temperature Normalization Adjustment	2,724	Sch. RJH-7
5. Annualized Depreciation Expense	16,621	Sch. RJH-8
6. Correction to Year-End Customer Annualization Adjustment	29	Sch. RJH-9
7. Labor Costs Adjustment	260	Sch. RJH-10
8. Employee Benefit Costs Adjustment	189	Sch. RJH-11
9. Ice Storm Amortization Expense Adjustment	426	Sch. RJH-12
10. MISO Net Expense Adjustment	619	Sch. RJH-13
11. New Bank Credit Facilities Adjustment	465	Sch. RJH-14
12. Kentucky Coal Tax Credit Adjustment	384	Sch. RJH-15
13. Normalized Legal Expense Adjustment	840	Sch. RJH-16
14. Normalized Uncollectible Expense Adjustment	450	Sch. RJH-17
15. EEI Dues Adjustment	95	Sch. RJH-18
16. Miscellaneous Expense Adjustments	22	Sch. RJH-19
17. AG-Recommended Pro Forma After-Tax Operating Income:	$ 181,863	

KENTUCKY UTILITIES COMPANY
INTEREST SYNCHRONIZATION ADJUSTMENT
($000)

	KU Jurisdictional (1)	Adjustments	AG	
1. Adjusted Capitalization	$ 2,073,463		$ 2,052,940	Sch. RJH-2
2. Weighted Cost of Debt	2.39%		2.40%	Sch. RJH-2
3. Pro Forma Interest Expense	49,556		$ 49,236	
4. Test Year Per Books Interest Deduction	46,369		46,369	
5. Interest Synchronization Adjustment	3,187		2,867	
6. Composite Income Tax Rate	37.60280%		37.60280%	
7. Impact on After-Tax Income	$ 1,198	$ (120)	$ 1,078	

(1) Rives Exhibit 1. Schedule 1.40

KENTUCKY UTILLITIES COMPANY
UNBILLED REVENUE ADJUSTMENT
($000)

	KU Jurisdictional (1)	Adjustments	AG
Unbilled Revenues at 4/30/07:			
Unbilled Base Revenues	$ 31,661		$ 31,661
FAC Revenues	-		
DSM Revenues	133		
ECR Revenues	1,117		
MSR/VDT/STOD PCR Revenues	(586)		
Total Unbilled Revenues	$ 32,325		$ 31,661
Unbilled Revenues at 4/30/08:			
Unbilled Base Revenues	$ 37,969		$ 37,969
FAC Revenues	409		
DSM Revenues	141		
ECR Revenues	1,404		
MSR/VDT/STOD PCR Revenues	(720)		
Total Unbilled Revenues	$ 39,203		$ 37,969
Difference Between 4/30/07 & 4/40/08 Unb. Rev.:			
Unbilled Base Revenues	$ (6,308)		$ (6,308)
FAC Revenues	(409)		
DSM Revenues	(8)		
ECR Revenues	(287)		
MSR/VDT/STOD PCR Revenues	134		
Total Unbilled Revenue Adjustment	$ (6,878)	$ 570	$ (6,308)
Composite After-Tax Income Factor (1 - .3760280)		62.3972%	
Impact on After-Tax Operating Income		$ 356	

(1) Rives Exhibit 1, Schedule 1.00; response to AG-1-18; response to AG-2-4

KENTUCKY UTILITIES COMPANY
TEMPERATURE NORMALIZATION ADJUSTMENT
($000)

	KU Jurisdictional (1)	Adjustments	AG	
1. Revenue Adjustment	$ (8,721)	$ 8,721	$ -	(2)
2. Variable Expense Adjustment	(4,355)	4,355	-	(2)
3. PSC Assessment and Uncollectibe Expense Adjustment @ .3633% of Line 1	-	-	-	
4. Total Net Weather Normalization Adjustment	$ (4,366)	$ 4,366	$ -	
5. Composite After-Tax Income Factor (1 - .3760280)		62.3972%		
6. Impact on After-Tax Operating Income		$ 2,724		

(1) Seelye Exhibit 13
(2) Testimony of Glenn Watkins

KENTUCKY UTILITIES COMPANY
ANNUALIZED DEPRECIATION EXPENSE ADJUSTMENT
($000)

	KU (1)	Adjustments	AG	
1. Annualized Depreciation Expense With New Rates	$ 111,536	$ (30,458)	$ 81,078	(2)
2. Test Year Per Books Depr. Exp. Excluding ARO and Post-1995 ECR	111,266		111,266	
3. Depreciation Expense Change	270		(30,188)	
4. KY Jurisdictional Allocation Ratio	87.457%		87.457%	
5. KY Jurisdictional Adjustment	$ 236	$ (26,638)	$ (26,402)	
6. Composite After-Tax Income Factor (1 - .3760280)		62.3972%		
7. Impact on After-Tax Operating Income		$ 16,621		

(1) Rives Exhibit 1, Schedule 1 14
(2) Testimony of Michael Majoros

Case No. 2008-00251 Sch. RJH-9

KENTUCKY UTILITIES COMPANY
CORRECTION TO YEAR-END CUSTOMER ANNUALIZATION ADJUSTMENT

	KU (1)	Adjustments	AG	
Decoratibve SL - SLDEC # of Customers:				
4/07	5,627		7,567	(2)
5/07	20,853		7,620	(2)
6/07	7,673		7,673	
7/07	7,705		7,705	
8/07	7,778		7,778	
9/07	7,793		7,793	
10/07	7,886		7,886	
11/07	8,007		8,007	
12/07	8,053		8,053	
1/08	8,139		8,139	
2/08	8,175		8,175	
3/08	8,186		8,186	
4/08	8,206		8,206	
1. 13-Month Average # of Customers	8,775		7,907	
2. Test Year-End # of Customers	8,206		8,206	
3. Customer Growth Year-End vs Average	(569)		299	
4. Annual Rate per Customer	$ 153.0314		$ 153.0314	
5. Revenue Annualization Adjustment	$ (87,145)	$ 132,937	$ 45,792	
6. Impact on Expense at Ratio of .6475		86,077		
7. Net Revenue Annualization Adjustment		46,860		
8. Composite After-Tax Income Factor (1 - .3760280)		62.3972%		
9. Impact on After-Tax Operating Income		$ 29,240		

(1) Seelye Exhibit 15, p. 1 and response to PSC-2-66

(2) Estimated normalized customer levels based on average monthly customer growth of 53

KENTUCKY UTILITIES COMPANY
LABOR COST ADJUSTMENT
($000)

	KU Jurisdictional (1)	Adjustments	AG	
1. Total Labor and Labor Related Cost Adjustment	$ 1,550	$ (224)	$ 1,326	(2)
2. Remove "Other Compensation" Expenses	-	(192)	(192)	(3)
3. Total Labor Cost Adjustment	$ 1,550	(416)	$ 1,134	
4. Composite After-Tax Income Factor (1 - .3760280)		62.3972%		
5. Impact on After-Tax Operating Income		$ 260		

(1) Rives Exhibit 1, Schedule 1.15
(2) Rives Exhibit 1, Schedule 1.15, Revised
(3) Response to PSC-2-102(f)2 and amended response to PSC-3-41

KENTUCKY UTILITIES COMPANY
EMPLOYEE BENEFIT COST ADJUSTMENT
($000)

	KU (1)	Adjustments	AG	
1. Pension Expense Adjustment	$ (436)	$ (271)	$ (707)	(2)
2. OPEB Expense Adjustment	265	(67)	198	(2)
3. Post-Employment Benefit Expense Adjustment	1,250	(2)	1,248	(2)
4. Total Employee Benefits Expense Adjustment	$ 1,079.00	(340)	$ 739	
5. KY Jurisdictional Allocation Ratio		89.139%		
6. Composite After-Tax Income Factor (1 - .3760280)		62.3972%		
7. Impact on After-Tax Operating Income		$ 189		

(1) Rives Exhibit 1, Schedules 1.16 and 1.17
(2) Rives Exhibit 1, Schedules 1.16 and 1.17, Revised

KENTUCKY UTILITIES COMPANY
ICE STORM AMORTIZATION EXPENSE ADJUSTMENT
($000)

1.	Unamortized Ice Storm Expense Balance at 4/30/08	$ 924	(1)
2.	Amortization from 4/30/08 to Rate Effective Date 2/6/09	(594)	(2)
3.	Unamortized Balance at Rate Effective Date 2/6/09	330	*
4.	New Amortization Period (Yrs)	3	
5.	Recommended Annual Amortization Expense	110	
6.	Amortization Expense in Test Year	792	(1)
7.	Amortization Expense Adjustment	(682)	
8.	Composite After-Tax Income Factor (1 - .3760280)	62.3972%	
9.	Impact on After-Tax Operating Income	$ 426	

* At the current monthly amortization rate of $66,000, this balance would be fully amortized on 6/30/09

(1) Response to AG-1-7
(2) Monthly amortization of $66,000 x 9 months = $594,000

KENTUCKY UTILITIES COMPANY
MISO NET COST ADJUSTMENT
($000)

1.	MISO Exit Fee Balance at 4/30/08 (Ky Jurisd.)	$ 16,362	Reference Sch. 1.23
2.	Estimated MISO Exit Fee Credits 5/1/08 - 2/6/09	(254)	(1)
3.	MISO Exit Fee Balance at 2/6/09	16,108	
4.	Cumulative Schedule 10 Receipts at 4/30/08	6,552	Reference Sch. 1.23
5.	Schedule 10 Receipts 5/1/08 - 2/6/09	2,948	PSC-2-109(e)
6.	Cumulative Schedule 10 Receipts at 2/6/09	9,500	
7.	Net of MISO Exit Fees and Schedule 10 Receipts at Rate Effective Date of 2/6/09 [Line 3 - Line 6]	6,608	
8.	Amortization Period (Yrs)	5	
9.	Annual Amortization of Net MISO Expenses	1,322	
10.	MISO Exit Fee Balance at 2/6/09 [Line 3]	16,108	
11.	MISO Exit Fee Balance Through 1st Q. 2015	13,996	(2)
12.	MISO Exit Fee Credits 2/6/09 - 1st Q. 2015	2,112	
13.	Amortization Period (Yrs)	6	
14.	Annual Exit Fee Credits Amortization	352	
15.	Net MISO Expense Amortization [Line 9 - Line 14]	970	
16.	KU's Proposed Net MISO Expense Amortization	1,962	Reference Sch. 1.23
17.	Recommended Amortization Expense Adjustment	(992)	
18.	Composite After-Tax Income Factor (1 - .3760280)	62.3972%	
19.	Impact on After-Tax Operating Income	$ 619	

(1) Per response to AG-1-39c: ($309.473 - $16.186) x 86.537%

(2) Per response to AG-1-39a: $16,173,417 x 86.537%

KENTUCKY UTILITIES COMPANY
NEW BANK CREDIT FACILITY EXPENSES
($000)

	KU (1)	Adjustments	AG	
1. Cost of New Bank Credit Facilities:				
- Required New Letter of Credit Amount	$ 200,000		$ 194,847	(2)
- Letter of Credit Fee	1.1%		0.7%	(3)
- Total Estimated Fees	2,200		1,364	
- Plus: Legal Costs	50		50	
- Total Cost of New Bank Credit Facilities	2,250	(836)	1,414	
2. KY Jurisdictional Allocation Ratio		89.139%		
3. Composite After-Tax Income Factor (1 - .3760280)		62.3972%		
4. Impact on After-Tax Operating Income		$ 465		

(1) Exhibit 1, Schedule 1.32 and response to PSC-2-10
(2) Response to PSC-3-34
(3) Response to PSC-2-134, updated 10/23/08

KENTUCKY UTILITIES COMPANY
KENTUCKY COAL TAX CREDIT
($000)

1. Actual Coal Tax Credits Received During Most Recent 5 Years:		
2003	$	84
2004		239
2005		177
2006		508
2007		2,491
Five-Year Average (Use as Property Tax Credit)		700
2. KY Jurisdictional Allocation Ratio		88.038%
3. Composite After-Tax Income Factor (1 - .3760280)		62.3972%
4. Impact on After-Tax Operating Income	$	384

Source: Response to PSC-2-116

KENTUCKY UTILITIES COMPANY
NORMALIZED LEGAL EXPENSE ADJUSTMENT
($000)

			CPI- All Urban Cons.	Adjusted Amount	
1. Actual Legal Expenses:					
2004	$	3,145	1.1123	$ 3,498	(1)
2005		4,192	1.0758	4,510	(1)
2006		3,585	1.0422	3,736	(1)
2007		4,902	1.0133	4,967	(1)
Test Year		6,110	1.0000	6,110	(1)
Five-Year Average				4,564	
Budgeted Legal Expenses for 2008				4,300	(1)
2. Recommended Normalized Legal Expenses				4,600	
3. Test Year Legal Expenses				6,110	
4. Legal Expense Adjustment				(1,510)	
5. KY Jurisdictional Allocation Ratio				89.139%	(2)
6. Composite After-Tax Income Factor (1 - .3760280)				62.3972%	
7. Impact on After-Tax Operating Income				$ 840	

(1) Response to AG-1-57
(2) Response to AG-2-26

KENTUCKY UTILITIES COMPANY
NORMALIZED UNCOLLECTIBLE EXPENSE ADJUSTMENT
($000)

1. Test Year Uncollectible Expenses	$ 3,331
2. Recommended Normalized Uncollectible Expense	2,564
3. Expense Adjustment (portion related to OMA Dispute)	(767)
4. KY Jurisdictional Allocation Ratio	94.069%
5. Composite After-Tax Income Factor (1 - .3760280)	62.3972%
6. Impact on After-Tax Operating Income	$ 450

Source: Response to AG-2-28

KENTUCKY UTILITIES COMPANY
EEI DUES ADJUSTMENT
($000)

1. Total EEI Dues in Test Year	$	378	(1)
2. Portion of EEI Dues Related to Legislative & Regulatory Advocacy and Public Relations		45.35%	(2)
3. Remove Portion of EEI Dues Dedicated to Lobbying		171	
4. KY Jurisdictional Allocation Ratio		89.139%	(1)
5. Composite After-Tax Income Factor (1 - .3760280)		62.3972%	
6. Impact on After-Tax Operating Income	$	95	

(1) Response to AG-2-23
(2) PSC Order in Case No. 2003-00434, pp. 44-45

KENTUCKY UTILITIES COMPANY
MISCELLANEOUS EXPENSE ADJUSTMENTS
($000)

1. Remove Expenses Related to Employee Gifts, Award Banquets, Social Events, and Parties	$	(14)	(1)
2. Remove Fines and Penalties		(4)	(2)
3. Remove Real Estate Reception and Community Involvement Expense		(18)	(3)
4. Toal Miscellaneous Expense Adjustments		(36)	
5. Composite After-Tax Income Factor (1 - .3760280)		62.3972%	
6. Impact on After-Tax Operating Income	$	22	

(1) Response to AG-1-68 and AG-2-25

(2) Response to AG-2-24: penalty expenses of $4,998 x jurisdictional allocation factor of 89.139%

(3) Real estate reception expenses [$16,309 x .94408]	$	15,397	AG-2-21
Sponsorship and commun. involvement exp. [$3,010 x .94069]		2,831	AG-2-22
	$	18,228	

APPENDIX I

PRIOR REGULATORY EXPERIENCE OF ROBERT J. HENKES

* = Testimonies prepared and submitted

ARKANSAS

Southwestern Bell Telephone Company Divestiture Base Rate Proceeding*	Docket 83-045-U	09/1983

DELAWARE

Delmarva Power and Light Company Electric Fuel Clause Proceeding	Docket 41-79	04/1980
Delmarva Power and Light Company Electric Fuel Clause Proceeding	Docket 80-39	02/1981
Delmarva Power and Light Company Sale of Power Station Generation	Complaint Docket 279-80	04/1981
Delmarva Power and Light Company Electric Base Rate Proceeding	Docket 81-12	06/1981
Delmarva Power and Light Company Gas Base Rate Proceeding*	Docket 81-13	08/1981
Delmarva Power and Light Company Electric Fuel Clause Proceeding*	Docket 82-45	04/1983
Delmarva Power and Light Company Electric Fuel Clause Proceeding*	Docket 83-26	04/1984
Delmarva Power and Light Company Electric Fuel Clause Proceeding*	Docket 84-30	04/1985
Delmarva Power and Light Company Electric Fuel Clause Proceeding*	Docket 85-26	03/1986
Delmarva Power and Light Company Report of DP&L Operating Earnings*	Docket 86-24	07/1986
Delmarva Power and Light Company Electric Base Rate Proceeding*	Docket 86-24	12/1986 01/1987
Delmarva Power and Light Company	Docket 85-26	10/1986

Report Re. PROMOD and Its Use in Fuel Clause Proceedings*		
Diamond State Telephone Company Base Rate Proceeding*	Docket 86-20	04/1987
Delmarva Power and Light Company Electric Fuel Clause Proceeding*	Docket 87-33	06/1988
Delmarva Power and Light Company Electric Fuel Clause Proceeding*	Docket 90-35F	05/1991
Delmarva Power and Light Company Electric Base Rate Proceeding*	Docket 91-20	10/1991
Delmarva Power and Light Company Gas Base Rate Proceeding*	Docket 91-24	04/1992
Artesian Water Company Water Base Rate Proceeding*	Docket 97-66	07/1997
Artesian Water Company Water Base Rate Proceeding*	Docket 97-340	02/1998
United Water Delaware Water Base Rate Proceeding*	Docket 98-98	08/1998
Delmarva Power and Light Company Revenue Requirement and Stranded Cost Reviews	Not Docketed	12/1998
Artesian Water Company Water Base Rate Proceeding*	Docket 99-197 (Direct Test.)	09/1999
Artesian Water Company Water Base Rate Proceeding*	Docket 99-197 (Supplement. Test)	10/1999
Tidewater Utilities/ Public Water Co. Water Base Rate Proceedings*	Docket No. 99-466	03/2000
Delmarva Power & Light Company Competitive Services Margin Sharing Proceeding*	Docket No. 00-314	03/2001
Artesian Water Company Water Base Rate Proceeding*	Docket No. 00-649	04/2001

Chesapeake Gas Company Gas Base Rate Proceeding*	Docket No. 01-307	12/2001
Tidewater Utilities Water Base Rate Proceeding*	Docket No. 02-28	07/2002
Artesian Water Company Water Base Rate Proceeding*	Docket No. 02-109	09/2002
Delmarva Power & Light Company Electric Cost of Service Proceeding	Docket No. 02-231	03/2003
Delmarva Power & Light Company Gas Base Rate Proceeding*	Docket No. 03-127	08/2003
Artesian Water Company Water Base Rate Proceeding*	Docket No. 04-42	08/2004
United Water Delaware Water Base Rate Proceeding*	Docket No. 06-174	10/2006

DISTRICT OF COLUMBIA

District of Columbia Natural Gas Co. Gas Base Rate Proceeding*	Formal Case 870	05/1988
District of Columbia Natural Gas Co. Gas Base Rate Proceeding*	Formal Case 890	02/1990
District of Columbia Natural Gas Co. Waiver of Certain GS Provisions	Formal Case 898	08/1990
Chesapeake and Potomac Telephone Co. Base Rate Proceeding*	Formal Case 850	07/1991
Chesapeake and Potomac Telephone Co. Base Rate Proceeding*	Formal Case 926	10/1993
Bell Atlantic - District of Columbia SPF Surcharge Proceeding	Formal Case 926	06/19/94
Bell Atlantic - District of Columbia Price Cap Plan and Earnings Review	Formal Case 814 IV	07/1995

GEORGIA

Southern Bell Telephone Company Base Rate Proceeding	Docket 3465-U	08/1984
Southern Bell Telephone Company Base Rate Proceeding	Docket 3518-U	08/1985
Georgia Power Company Electric Base Rate and Nuclear Power Plant Phase-In Proceeding*	Docket 3673-U	08/1987
Georgia Power Company Electric Base Rate and Nuclear Power Plant Phase-In Proceeding*	Docket 3840-U	08/1989
Southern Bell Telephone Company Base Rate Proceeding	Docket 3905-U	08/1990
Southern Bell Telephone Company Implementation, Administration and Mechanics of Universal Service Fund*	Docket 3921-U	10/1990
Atlanta Gas Light Company Gas Base Rate Proceeding*	Docket 4177-U	08/1992
Southern Bell Telephone Company Report on Cash Working Capital*	Docket 3905-U	03/1993
Atlanta Gas Light Company Gas Base Rate Proceeding*	Docket No. 4451-U	08/1993
Atlanta Gas Light Company Gas Base Rate Proceeding	Docket No. 5116-U	08/1994
Georgia Independent Telephone Companies Earnings Review and Show Cause Proceedings	Various Dockets	1994
Georgia Power Company Earnings Review - Report to GPSC*	Non-Docketed	09/1995
Georgia Alltel Telecommunication Companies Earnings and Rate Reviews	Docket No. 6746-U	07/1996
Frontier Communications of Georgia Earnings and Rate Review	Docket No. 4997-U	07/1996

Georgia Power Company Electric Base Rate / Accounting Order Proceeding	Docket No. 9355-U	12/1998
Savannah Electric Power Company Electric Base Rate Case/Alternative Rate Plan*	Docket No. 14618-U	03/2002
Georgia Power Company Electric Base Rate / Alternative Rate Plan Proceeding*	Docket No. 18300-U	12/2004
Savannah Electric Power Company Electric Base Rate Case/Alternative Rate Plan*	Docket No. 19758-U	03/2005
Georgia Power Company Electric Base Rate Case/Alternative Rate Plan*	Docket No. 25060-U	10/2007

<u>FERC</u>

Philadelphia Electric/Conowingo Power Electric Base Rate Proceeding*	Docket ER 80-557/558	07/1981

<u>KENTUCKY</u>

Kentucky Power Company Electric Base Rate Proceeding*	Case 8429	04/1982
Kentucky Power Company Electric Base Rate Proceeding*	Case 8734	06/1983
Kentucky Power Company Electric Base Rate Proceeding*	Case 9061	09/1984
South Central Bell Telephone Company Base Rate Proceeding*	Case 9160	01/1985
Kentucky-American Water Company Base Rate Proceeding*	Case 97-034	06/1997
Delta Natural Gas Company Base Rate Proceeding*	Case 97-066	07/1997
Kentucky Utilities and LG&E Company Environmental Surcharge Proceeding	97-SC-1091-DG	01/1999

Delta Natural Gas Company Experimental Alternative Regulation Plan*	Case No. 99-046	07/1999
Delta Natural Gas Company Base Rate Proceeding*	Case No. 99-176	09/1999
Louisville Gas & Electric Company Gas Base Rate Proceeding*	Case No. 2000-080	06/2000
Kentucky-American Water Company Base Rate Proceeding*	Case No. 2000-120	07/2000
Jackson Energy Cooperative Corporation Electric Base Rate Proceeding*	Case No. 2000-373	02/2001
Kentucky-American Water Company Base Rate Rehearing*	Case No. 2000-120	02/2001
Kentucky-American Water Company Rehearing Opposition Testimony*	Case No. 2000-120	03/2001
Union Light Heat and Power Company Gas Base Rate Proceeding*	Case No. 2001-092	09/2001
Louisville Gas & Electric Company and Kentucky Utilities Company Deferred Debits Accounting Order	Case No. 2001-169	10/2001
Fleming-Mason Energy Cooperative Electric Base Rate Proceeding	Case No. 2001-244	05/2002
Northern Kentucky Water District Water District Base Rate Proceeding	Case No. 2003-0224	02/2004
Louisville Gas & Electric Company Electric Base Rate Proceeding*	Case No. 2003-0433	03/2004
Louisville Gas & Electric Company Gas Base Rate Proceeding*	Case No. 2003-0433	03/2004
Delta Natural Gas Company Base Rate Proceeding*	Case No. 2004-00067	07/2004
Union Light Heat and Power Company Gas Base Rate Proceeding*	Case No. 2005-00042	06/2005

Big Sandy Rural Electric Cooperative Electric Base Rate Proceeding	Case No. 2005-00125	08/2005
Louisville Gas & Electric Company Value Delivery Surcredit Mechanism*	Case No. 2005-00352	12/2005
Kentucky Utilities Company Value Delivery Surcredit Mechanism*	Case No. 2005-00351	12/2005
Kentucky Power Company Electric Base Rate Proceeding*	Case No. 2005-00341	01/2006
Cumberland Valley Electric Cooperative Electric Base Rate Proceeding	Case No. 2005-00187	05/2006
South Kentucky Rural Electric Cooperative Electric Base Rate Proceeding	Case No. 2005-00450	07/2006
Duke Energy Kentucky Electric Base Rate Proceeding*	Case No. 2006-00172	09/2006
Atmos Energy Corporation Gas Show Cause Proceeding*	Case No. 2005-00057	09/2006
Inter County Electric Cooperative Electric Base Rate Proceeding	Case No. 2006-00415	04/2007
Atmos Energy Corporation Gas Base Rate Proceeding*	Case No. 2006-00464	04/2007
Columbia Gas of Kentucky Gas Base Rate Proceeding*	Case No. 2007-00008	06/2007
Delta Natural Gas Company Gas Base Rate Proceeding – Alternative Rate Mechanism*	Case No. 2007-00089	08/2007
Nolin Rural Electric Cooperative Corporation Electric Rate Proceeding	Case No. 2006-00466	09/2007
Fleming-Mason Energy Cooperative Electric Base Rate Proceeding	Case No. 2006-00022	10/2007
Jasckson Energy Cooperative Electric Base Rate Proceeding	Case No 2007-00333	03/2008

Jackson Purchase Energy Corporation Electric Base Rate Proceeding	Case No. 2007-00116	04/2008
Blue Grass Energy Cooperative Electric Base Rate Proceeding	Case No. 2008-00011	7/2008

MAINE

Continental Telephone Company of Maine Base Rate Proceeding	Docket 90-040	12/1990
Central Maine Power Company Electric Base Rate Proceeding	Docket 90-076	03/1991
New England Telephone Corporation - Maine Chapter 120 Earnings Review	Docket 94-254	12/1994

MARYLAND

Potomac Electric Power Company Electric Base Rate Proceeding*	Case 7384	01/1980
Delmarva Power and Light Company Electric Base Rate Proceeding*	Case 7427	08/1980
Chesapeake and Potomac Telephone Company Western Electric and License Contract	Case 7467	10/1980
Chesapeake and Potomac Telephone Company Base Rate Proceeding*	Case 7467	10/1980
Washington Gas Light Company Gas Base Rate Proceeding	Case 7466	11/1980
Delmarva Power and Light Company Electric Base Rate Proceeding*	Case 7570	10/1981
Chesapeake and Potomac Telephone Company Base Rate Proceeding*	Case 7591	12/1981
Chesapeake and Potomac Telephone Company Base Rate Proceeding*	Case 7661	11/1982

Chesapeake and Potomac Telephone Company Computer Inquiry II*	Case 7661	12/1982
Chesapeake and Potomac Telephone Company Divestiture Base Rate Proceeding*	Case 7735	10/1983
AT&T Communications of Maryland Base Rate Proceeding	Case 7788	1984
Chesapeake and Potomac Telephone Company Base Rate Proceeding*	Case 7851	03/1985
Potomac Electric Power Company Electric Base Rate Proceeding	Case 7878	1985
Delmarva Power and Light Company Electric Base Rate Proceeding	Case 7829	1985

NEW HAMPSHIRE

Granite State Electric Company Electric Base Rate Proceeding	Docket DR 77-63	1977

NEW JERSEY

Elizabethtown Water Company Water Base Rate Proceeding	Docket 757-769	07/1975
Jersey Central Power and Light Company Electric Base Rate Proceeding	Docket 759-899	09/1975
Middlesex Water Company Water Base Rate Proceeding	Docket 761-37	01/1976
Jersey Central Power and Light Company Electric Base Rate Proceeding	Docket 769-965	09/1976
Public Service Electric and Gas Company Electric and Gas Base Rate Proceedings	Docket 761-8	10/1976
Atlantic City Electric Company Electric Base Rate Proceeding*	Docket 772-113	04/1977

Public Service Electric and Gas Company Electric and Gas Base Rate Proceedings*	Docket 7711-1107	05/1978
Public Service Electric and Gas Company Raw Materials Adjustment Clause	Docket 794-310	04/1979
Rockland Electric Company Electric Base Rate Proceeding*	Docket 795-413	09/1979
New Jersey Bell Telephone Company Base Rate Proceeding	Docket 802-135	02/1980
Rockland Electric Company Electric Fuel Clause Proceeding*	Docket 8011-836	02/1981
Rockland Electric Company Electric Base Rate Proceeding*	Docket 811-6	05/1981
Rockland Electric Company Electric Fuel Clause Proceeding*	Docket 8110-883	02/1982
Public Service Electric and Gas Company Electric Fuel Clause Proceeding*	Docket 812-76	08/1982
Public Service Electric and Gas Company Raw Materials Adjustment Clause	Docket 812-76	08/1982
New Jersey Bell Telephone Company Base Rate Proceeding	Docket 8211-1030	11/1982
Rockland Electric Company Electric Fuel Clause Proceeding*	Docket 829-777	12/1982
Public Service Electric and Gas Company Electric and Gas Base Rate Proceedings*	Docket 837-620	10/1983
New Jersey Bell Telephone Company Base Rate Proceeding	Docket 8311-954	11/1983
AT&T Communications of New Jersey Base Rate Proceeding*	Docket 8311-1035	02/1984
Rockland Electric Company Electric Fuel Clause Proceeding*	Docket 849-1014	11/1984
AT&T Communications of New Jersey	Docket 8311-1064	05/1985

Base Rate Proceeding*

Public Service Electric and Gas Company Electric and Gas Base Rate Proceedings*	Docket ER8512-1163	05/1986
Public Service Electric and Gas Company Electric Fuel Clause Proceeding*	Docket ER8512-1163	07/1986
Rockland Electric Company Electric Fuel Clause Proceeding*	Docket ER8609-973	12/1986
Rockland Electric Company Electric Fuel Clause Proceeding*	Docket ER8710-1189	01/1988
Public Service Electric and Gas Company Electric Fuel Clause Proceeding*	Docket ER8512-1163	02/1988
United Telephone of New Jersey Base Rate Proceeding	Docket TR8810-1187	08/1989
Rockland Electric Company Electric Fuel Clause Proceeding*	Docket ER9009-10695	09/1990
United Telephone of New Jersey Base Rate Proceeding	Docket TR9007-0726J	02/1991
Elizabethtown Gas Company Gas Base Rate Proceeding*	Docket GR9012-1391J	05/1991
Rockland Electric Company Electric Fuel Clause Proceeding	Docket ER9109145J	11/1991
Jersey Central Power and Light Company Electric Fuel Clause Proceeding	Docket ER91121765J	03/1992
New Jersey Natural Gas Company Gas Base Rate Proceeding*	Docket GR9108-1393J	03/1992
Public Service Electric and Gas Company Electric and Gas Base Rate Proceedings*	Docket ER91111698J	07/1992
Rockland Electric Company Electric Fuel Clause Proceeding	Docket ER92090900J	12/1992
Middlesex Water Company Water Base Rate Proceeding*	Docket WR92090885J	01/1993

Elizabethtown Water Company Water Base Rate Proceeding*	Docket WR92070774J	02/1993
Public Service Electric and Gas Company Electric Fuel Clause Proceeding	Docket ER91111698J	03/1993
New Jersey Natural Gas Company Gas Base Rate Proceeding*	Docket GR93040114	08/1993
Atlantic City Electric Company Electric Fuel Clause Proceeding	Docket ER94020033	07/1994
Borough of Butler Electric Utility Various Electric Fuel Clause Proceedings	Docket ER94020025	1994
Elizabethtown Water Company Water Base Rate Proceeding	Non-Docketed	11/1994
Public Service Electric and Gas Company Electric Fuel Clause Proceeding	Docket ER 94070293	11/1994
Rockland Electric Company Electric Fuel Clause Proceeding and Purchased Power Contract By-Out	Docket Nos. 940200045 and ER 9409036	12/1994
Jersey Central Power & Light Company Electric Fuel Clause Proceeding	Docket ER94120577	05/1995
Elizabethtown Water Company Purchased Water Adjustment Clause Proceeding*	Docket WR95010010	05/1995
Middlesex Water Company Purchased Water Adjustment Clause Proceeding	Docket WR94020067	05/1995
New Jersey American Water Company* Base Rate Proceeding	Docket WR95040165	01/1996
Rockland Electric Company Electric Fuel Clause Proceeding	Docket ER95090425	01/1996
United Water of New Jersey Base Rate Proceeding*	Docket WR95070303	01/1996
Elizabethtown Water Company Base Rate Proceeding*	Docket WR95110557	03/1996

New Jersey Water and Sewer Adjustment Clauses Rulemaking Proceeding*	Non-Docketed	03/1996
United Water Vernon Sewage Company Base Rate Proceeding*	Docket WR96030204	07/1996
United Water Great Gorge Company Base Rate Proceeding*	Docket WR96030205	07/1996
South Jersey Gas Company Base Rate Proceeding	Docket GR960100932	08/1996
Middlesex Water Company Purchased Water Adjustment Clause Proceeding*	Docket WR96040307	08/1996
Atlantic City Electric Company Fuel Adjustment Clause Proceeding*	Docket No.ER96030257	08/1996
Public Service Electric & Gas Company and Atlantic City Electric Company Investigation into the continuing outage of the Salem Nuclear Generating Station*	Docket Nos. ES96039158 & ES96030159	10/1996
Rockland Electric Company Electric Fuel Clause Proceeding*	Docket No.EC96110784	01/1997
Consumers New Jersey Water Company Base Rate Proceeding*	Docket No.WR96100768	03/1997
Atlantic City Electric Company Fuel Adjustment Clause Proceeding*	Docket No.ER97020105	08/1997
Public Service Electric & Gas Company Electric Restructuring Proceedings*	Docket Nos. EX912058Y, EO97070461, EO97070462, EO97070463	11/1997
Atlantic City Electric Company Limited Issue Rate Proceeding*	Docket No.ER97080562	12/1997
Rockland Electric Company Limited Issue Rate Proceeding	Docket No.ER97080567	12/1997
South Jersey Gas Company Limited Issue Rate Proceeding	Docket No.GR97050349	12/1997

New Jersey American Water Company Limited Issue Rate Proceeding	Docket No.WR97070538	12/1997
Elizabethtown Water Company and Mount Holly Water Company Limited Issue Rate Proceedings	Docket Nos. WR97040288, WR97040289	12/1997
United Water of New Jersey, United Water Toms River and United Water Lambertville Limited Issue Rate Proceedings	Docket Nos.WR9700540, WR97070541, WR97070539	12/1997
Public Service Electric & Gas Company Electric Restructuring Proceedings*	Docket Nos. EX912058Y, EO97070461, EO97070462, EO97070463	01/1998
Consumers New Jersey Water Company Base Rate Proceeding*	Docket No. WR97080615	01/1998
New Jersey-American Water Company Base Rate Proceeding*	Docket No.WR98010015	07/1998
Consumers New Jersey Water Company Merger Proceeding	Docket No.WM98080706	12/1998
Atlantic City Electric Company Fuel Adjustment Clause Proceeding*	Docket No.ER98090789	02/1999
Middlesex Water Company Base Rate Proceeding*	Docket No.WR98090795	03/1999
Mount Holly Water Company Base Rate Proceeding - Phase I*	Docket No. WR99010032	07/1999
Mount Holly Water Company Base Rate Proceeding - Phase II*	Docket No. WR99010032	09/1999
New Jersey American Water Company Acquisitions of Water Systems	Docket Nos WM9910018 WM9910019	09/1999 09/1999
Mount Holly Water Company Merger with Homestead Water Utility	Docket No. WM99020091	10/1999
Applied Wastewater Management, Inc. Merger with Homestead Treatment Utility	Docket No.WM99020090	10/1999
Environmental Disposal Corporation (Sewer)	Docket No.WR99040249	02/2000

Base Rate Proceeding*

Elizabethtown Gas Company		
Gas Cost Adjustment Clause Proceeding	Docket No.GR99070509	03/2000
DSM Adjustment Clause Proceeding	Docket No. GR99070510	03/2000
New Jersey American Water Company Gain on Sale of Land	Docket No. WM99090677	04/2000
Jersey Central Power & Light Company NUG Contract Buydown	Docket No. EM99120958	04/2000
Shore Water Company Base Rate Proceeding	Docket No. WR99090678	05/2000
Shorelands Water Company Water Diversion Rights Acquisition	Docket No. WO00030183	05/2000
Mount Holly and Elizabethtown Water Companies Computer and Billing Services Contracts	Docket Nos. WO99040259 WO9904260	06/2000 06/2000
United Water Resources, Inc. Merger with Suez-Lyonnaise	Docket No. WM99110853	06/2000
E'Town Corporation Merger with Thames, Ltd.	Docket No. WM99120923	08/2000
Consumers Water Company Water Base Rate Proceeding*	Docket No. WR00030174	09/2000
Atlantic City Electric Company Buydown of Purchased Power Contract	Docket No. EE00060388	09/2000
Applied Wastewater Management, Inc. Authorization for Accounting Changes	Docket No. WR00010055	10/2000
Elizabethtown Gas Company		
Gas Cost Adjustment Clause Proceeding	Docket No. GR00070470	10/2000
DSM Adjustment Clause Proceeding	Docket No. GR00070471	10/2000
Trenton Water Works Water Base Rate Proceeding*	Docket No. WR00020096	10/2000
Middlesex Water Company Water Base Rate Proceeding*	Docket No. WR00060362	11/2000

New Jersey American Water Company Land Sale - Ocean City	Docket No. WM00060389	11/2000
Pineland Water Company Water Base Rate Proceeding*	Docket No. WR00070454	12/2000
Pineland Wastewater Company Wastewater Base Rate Proceeding*	Docket No. WR00070455	12/2000
Elizabethtown Gas Company Regulatory Treatment of Gain on Sale of Property*	Docket No. GR00070470	02/2001
Wildwood Water Utility Water Base Rate Proceeding*	Docket No. WR00100717	04/2001
Roxbury Water Company Water Base Rate Proceeding	Docket No. WR01010006	06/2001
SB Water Company Water Base Rate Proceeding	Docket No. WR01040232	06/2001
Pennsgrove Water Company Water Base Rate Proceeding*	Docket No. WR00120939	07/2001
Public Service Electric & Gas Company Gas Base Rate Proceeding* Direct Testimony	Docket No. GR01050328	08/2001
Public Service Electric & Gas Company Gas Base Rate Proceeding* Surrebuttal Testimony	Docket No. GR01050328	09/2001
Elizabethtown Water Company Water Base Rate Proceeding*	Docket No. WR01040205	10/2001
Middlesex Water Company Financing Proceeding	Docket No. WF01090574	12/2001
New Jersey American Water Company Financing Proceeding	Docket No. WF01050337	12/2001
Consumers New Jersey Water Company Stock Transfer/Change in Control Proceeding	Docket No. WF01080523	01/2002
Consumers New Jersey Water Company	Docket No. WR02030133	07/2002

Water Base Rate Proceeding

New Jersey American Water Company Change of Control (Merger) Proceeding*	Docket No. WM01120833	07/2002
Borough of Haledon – Water Department Water Base Rate Proceeding*	Docket No. WR01080532	07/2002
New Jersey American Water Company Change of Control (Merger) Proceeding	Docket No. WM02020072	09/2002
Public Service Electric & Gas Company Electric Base Rate Proceeding Direct Testimony*	Docket No. ER02050303	10/2002
United Water Lambertville Land Sale Proceeding	Docket No. WM02080520	11/2002
United Water Vernon Hills & Hampton Management Service Agreement	Docket No. WE02080528	11/2002
United Water New Jersey Metering Contract With Affiliate	Docket No. WO02080536	12/2002
Public Service Electric & Gas Company Electric Base Rate Proceeding Surrebuttal and Supplemental Surrebuttal Testimonies*	Docket No. ER02050303	12/2002
Public Service Electric & Gas Company Minimum Pension Liability Proceeding	Docket No. EO02110853	12/2002
Public Service Electric & Gas Company Electric Base Rate Proceeding Supplemental Direct Testimony*	Docket No. ER02050303	12/2002
Public Service Electric & Gas Company Electric Deferred Balance Proceeding Direct Testimony*	Docket No. ER02050303	01/2003
Rockland Electric Company Electric Base Rate Proceeding Direct Testimony*	Docket No. ER02100724	01/2003
Public Service Electric & Gas Company Supplemental Direct Testimony*	Docket No. ER02050303	02/2003

Rockland Electric Company Electric Base Rate Proceeding Supplemental Direct Testimony*	Docket No. ER02100724	02/2003
Consumers New Jersey Water Company Acquisition of Maxim Sewerage Company	Docket No. WM02110808	05/2003
Rockland Electric Company Audit of Competitive Services	Docket No. EA02020098	06/2003
New Jersey Natural Gas Company Audit of Competitive Services	Docket No. GA02020100	06/2003
Public Service Electric & Gas Company Audit of Competitive Services	Docket No. EA02020097	06/2003
Mount Holly Water Company Water Base Rate Proceeding*	Docket No. WR03070509	12/2003
Elizabethtown Water Company Water Base Rate Proceeding*	Docket No. WR03070510	12/2003
New Jersey-American Water Company Water and Sewer Base Rate Proceeding*	Docket No. WR03070511	12/2003
Applied Wastewater Management, Inc. Water and Sewer Base Rate Proceeding*	Docket No. WR03030222	01/2004
Middlesex Water Company Water Base Rate Proceeding	Docket No. WR03110900	04/2004
Consumers New Jersey Water Company Water Base Rate Proceeding	Docket No. WR02030133	07/2004
Roxiticus Water Company Purchased Water Adjustment Clause	Docket No. WR04060454	08/2004
Rockland Electric Company Societal Benefit Charge Proceeding	Docket No. ET04040235	08/2004
Wildwood Water Utility Water Base Rate Proceeding - Interim Rates	Docket No. WR04070620	08/2004
United Water Toms River Litigation Cost Accounting Proceeding	Docket No. WF04070603	11/2004

Lake Valley Water Company Water Base Rate Proceeding	Docket No. WR04070722	12/2004
Public Service Electric & Gas Company Customer Account System Proceeding	Docket No. EE04070718	02/2005
Jersey Central Power and Light Company Various Land Sales Proceedings	Docket No. EM04101107 Docket No. EM04101073 Docket No. EM04111473	02/2005 02/2005 03/2005
Environmental Disposal Corporation Water Base Rate Proceeding	Docket No. WR040080760	05/2005
Universal Service Fund Compliance Filing For 7 New Jersey Electric and Gas Utilities	Docket No. EX00020091	05/2005
Rockland Electric Company Societal Benefit Charge Proceeding	Docket No. ET05040313	08/2005
Public Service Electric & Gas Company Buried Underground Distribution Tariff Proceeding	Docket No. ET05010053	08/2005
Aqua New Jersey Acquisition of Berkeley Water Co. Water Merger Proceeding	Docket No. WM04121767	08/2005
Middlesex Water Company Water Base Rate Proceeding	Docket No. WR05050451	10/2005
Public Service Electric & Gas Company Land Sale Proceeding	Docket No. EM05070650	10/2005
Public Service Electric & Gas Company Merger of PSEG and Exelon Corporation Direct Testimony	Docket No. EM05020106	11/2005
Public Service Electric & Gas Company* Merger of PSEG and Exelon Corporation Surrebuttal Testimony	Docket No. EM05020106	12/2005
Public Service Electric & Gas Company* Financial Review of Electric Operations	Docket No. ER02050303	12/2005
Rockland Electric Company Competitive Services Audit	Docket No. EA02020098	12/2005
Public Service Electric & Gas Company	Docket No. EE04070718	01/2006

Customer Accounting System Cost Recovery	
Roxiticus Water Company Stock Sale and Change of Ownership and Control	Docket No. WM05080755 01/2006
Public Service Electric & Gas Company Competitive Services Audit	Docket No. EA02020097 02/2006
Wildwood Water Company Water Base Rate Proceeding	Docket No. WR05070613 03/2006
Pinelands Water Company Water Base Rate Proceeding*	Docket No. WR05080681 03/2006
Pinelands Wastewater Company Wastewater Base Rate Proceeding*	Docket No. WR05080680 03/2006
Aqua New Jersey Water Company Water Base Rate Proceeding*	Docket No. WR05121022 06/2006
Public Service Electric & Gas Company Gas Base Rate Proceeding*	Docket No. GR05100845 07/2006
New Jersey American Company Consolidated Water Base Rate Proceeding,* New Jersey American Water Company, Elizabethtown Water Company, and Mount Holly Water Company	Docket No. WR06030257 10/2006
Roxiticus Water Company Water Base Rate Proceeding	Docket No. WR06120884 04/2007
United Water Company of New Jersey Change of Control Proceeding	Docket No. WM06110767 05/2007
United Water Company of New Jersey Water Base Rate Proceeding*	Docket No. WR07020135 09/2007
Middlesex Water Company Water Base Rate Proceeding	Docket No. WR07040275 09/2007
Maxim Wastewater Company Purchased Sewerage Treatment Adjustment Clause	Docket No. WR07080632 11/2007
Fayson Lake Water Company Financing Case	Docket No. WF07080593 12/2007

Atlantic City Electric Company Sales of Utility Properties	Docket No. EM07100800	12/2007
Atlantic City Sewerage Company Base Rate and Purchased Sewerage Treatment Clause Proceedings	Docket No. WR07110866	04/2008
SB Water Company Water Base Rate Proceeding	Docket No. WR07110840	04/2008
Aqua New Jersey Water Company Water Base Rate Proceeding	Docket No. WR07120955	06/2008
Environmental Disposal Corporation Water Base Rate Proceeding	Docket No. WR07090715	06/2008
Middlesex Water Company Financing Case	Docket No. WF08040213	07/2008
Aqua New Jersey Water Company Franchise Case	Docket No. WE08040230	07/2008
Aqua New Jersey Water Company Financing Case	Docket No. WF08040216	07/2008
New Jersey American Water Company Water Base Rate Proceeding*	Docket No. WR08010020	07/2008
United Water Toms River, Inc. Water Base Rate Proceeding	Docket No. WR08030139	08/2008

NEW MEXICO

Southwestern Public Service Company Electric Base Rate Proceeding*	Case 1957	11/1985
El Paso Electric Company Rate Moderation Plan	Case 2009	1986
El Paso Electric Company Electric Base Rate Proceeding	Case 2092	06/1987

Gas Company of New Mexico Gas Base Rate Proceeding*	Case 2147	03/1988
El Paso Electric Company Electric Base Rate Proceeding*	Case 2162	06/1988
Public Service Company of New Mexico Phase-In Plan*	Case 2146/Phase II	10/1988
El Paso Electric Company Electric Base Rate Proceeding*	Case 2279	11/1989
Gas Company of New Mexico Gas Base Rate Proceeding*	Case 2307	04/1990
El Paso Electric Company Rate Moderation Plan*	Case 2222	04/1990
Generic Electric Fuel Clause - New Mexico Amendments to NMPSC Rule 550	Case 2360	02/1991
Southwestern Public Service Company Rate Reduction Proceeding	Case 2573	03/1994
El Paso Electric Company Base Rate Proceeding	Case 2722	02/1998

OHIO

Dayton Power and Light Company Electric Base Rate Proceeding	Case 76-823	1976

PENNSYLVANIA

Duquesne Light Company Electric Base Rate Proceeding*	R.I.D. No. R-821945	09/1982
AT&T Communications of Pennsylvania Base Rate Proceeding*	Docket P-830452	04/1984
AT&T Communications of Pennsylvania Base Rate Proceeding*	Docket P-830452	11/1984
National Fuel Gas Distribution Company	Docket R-870719	12/1987

Gas Base Rate Proceeding*

RHODE ISLAND

Blackstone Valley Electric Company Electric Base Rate Proceeding	Docket No. 1289	
Newport Electric Company Report on Emergency Relief		

VERMONT

Continental Telephone Company of Vermont Base Rate Proceeding	Docket No. 3986	
Green Mountain Power Corporation Electric Base Rate Proceeding	Docket No. 5695	01/1994
Central Vermont Public Service Corp. Rate Investigation	Docket No. 5701	04/1994
Central Vermont Public Service Corp. Electric Base Rate Proceeding*	Docket No. 5724	05/1994
Green Mountain Power Corporation Electric Base Rate Proceeding*	Docket No. 5780	01/1995
Green Mountain Power Corporation Electric Base Rate Proceeding*	Docket No. 5857	01/1996

VIRGIN ISLANDS

Virgin Islands Telephone Corporation Base Rate Proceeding*	Docket 126	

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF KENTUCKY UTILITIES COMPANY, INC. FOR AN ADJUSTMENT OF BASE RATES	)))	Case No. 2008-00251 C/W Case No. 2007-00565

AFFIDAVIT OF ROBERT J. HENKES

State of Connecticut)
)
)

Robert J. Henkes, being first duly sworn, states the following: The prepared Pre-Filed Direct Testimony, and the Schedules and Appendix attached thereto constitute the direct testimony of Affiant in the above-styled case. Affiant states that he would give the answers set forth in the Pre-Filed Direct Testimony if asked the questions propounded therein. Affiant further states that, to the best of his knowledge, his statements made are true and correct. Further affiant saith not.

Robert J. Henkes

SUBSCRIBED AND SWORN to before me this 21 day of Oct, 2008.

NOTARY PUBLIC

My Commission Expires: 2/28/10

LISA A. LATTANZIO
My Commission
NOTARY
PUBLIC
EXPIRES
02-28-2010
CONNECTICUT

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

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COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF KENTUCKY UTILITIES	)	**Case No. 2008-00251**
COMPANY FOR AN ADJUSTMENT OF	)	**C/W**
ELECTRIC BASE RATES	)	**Case No. 2007-00565**

Direct Testimony of
Dr. J. Randall Woolridge

on Behalf of
the Office of the Attorney General

October 28, 2008

Kentucky Utilities Company

Direct Testimony of
Dr. J. Randall Woolridge

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LIST OF EXHIBIT

Q. PLEASE STATE YOUR FULL NAME, ADDRESS, AND OCCUPATION.

A. My name is J. Randall Woolridge, and my business address is 120 Haymaker Circle, State College, PA 16801. I am a Professor of Finance and the Goldman, Sachs & Co. and Frank P. Smeal Endowed University Fellow in Business Administration at the University Park Campus of the Pennsylvania State University. I am also the Director of the Smeal College Trading Room and President of the Nittany Lion Fund, LLC. A summary of my educational background, research, and related business experience is provided in Appendix A.

I. SUBJECT OF TESTIMONY AND SUMMARY OF RECOMMENDATIONS

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. I have been asked by the Kentucky Office of Attorney General ("OAG") to provide an opinion as to the overall fair rate of return or cost of capital for the Kentucky Utilities Company ("KU" or "Company") and to evaluate KU's rate of return testimony in this proceeding.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. First I will review my cost of capital recommendation for KU, and review the primary areas of contention between KU's rate of return position and OAG. Second, I provide an assessment of capital costs in today's capital markets.

Third, I discuss my proxy group of electric utility companies for estimating the cost of capital for KU. Fourth, I present my recommendations for the Company's capital structure and debt cost rate. Fifth, I discuss the concept of the cost of equity capital, and then estimate the equity cost rate for KU. Finally, I critique Company's rate of return analysis and testimony. I have a table of contents just after the title page for a more detailed outline.

Q. PLEASE REVIEW YOUR RECOMMENDATIONS REGARDING THE APPROPRIATE RATE OF RETURN FOR KU.

A. I am using the capital structure developed by OAG Witness Robert Henkes. My analysis indicates that the capital structure ratios, which are identical to those proposed by KU, are very fair given the capitalizations of electric utility and gas distribution companies. I have adopted the Company's proposed short-term and long-term debt cost rates. I have applied the Discounted Cash Flow Model ("DCF") and the Capital Asset Pricing Model ("CAPM") to a proxy group of publicly-held electric utility companies. My analysis indicates an equity cost rate in the range of 8.2%-9.9% for KU's electric utility operations. I have used the upper end of the range – 9.9% - as my equity cost rate in recognition of the volatile capital market conditions. However, I reserve the right to update my equity cost rate recommendation prior to hearings. This is because, in my opinion, the current market conditions are in disequilibrium as investors attempt to sort out the economic consequences of the collapse of the financial sector and the unprecedented bail out by the U. S.

government. In addition, certain financial data have not been updated to reflect the current economic situation. Using my capital structure and debt and equity cost rates, I am recommending an overall rate of return of 7.61% for KU. This recommendation is summarized in Exhibit JRW-1.

Q. PLEASE SUMMARIZE THE PRIMARY ISSUES REGARGING RATE OF RETURN IN THIS PROCEEDING.

A. Mr. S. Bradford Rives provides the Company's proposed capital structure and debt cost rates and Dr. William E. Avera provides KU's proposed common equity cost rate. My analysis suggests that the Company's recommended capital structure with a common equity ratio of 52.63% is very fair to KU. I do employ the Company's debt cost rates. As such, the primary area of contention in this case is the proposed equity cost rate for KU. Dr. Avera's equity cost rate estimate is 11.25%, whereas my analysis indicates an equity cost rate of 9.90% is appropriate for KU.

Both Dr. Avera and I have applied the DCF and the CAPM approaches to groups of publicly-held electric utility companies. Dr. Avera has also used an Expected Earnings approach to estimate an equity cost rate for KU. As discussed in my testimony, my equity cost rate recommendation is consistent with the current economic environment. Long-term capital costs are at historical low levels. The yields on long-term Treasury bonds have been in the 4-5 percent range for several years. Prior to this cyclical decline in rates in 2002, these yields had not been this low over an extended period of time since the 1960s. Long-term capital costs are also low due to the decline in the equity risk premium and the Jobs and Growth Tax Relief Reconciliation Act of 2003, which reduced the tax rates on dividend income and capital gains.

Dr. Avera employs a proxy group that includes several companies which receive a low percentage of revenues from regulated utility operations. In addition, he employs an inappropriate non-utility proxy group. With respect to the application of the DCF model, the major area of disagreement is the expected DCF growth rate. Dr. Avera relies on the earnings per share ("EPS") growth rate forecasts of Wall Street analysts and *Value Line* for his DCF growth rate. I demonstrate that there is a well-known upward bias to these growth rate forecasts.

The CAPM approach requires an estimate of the risk-free interest rate, beta, and the equity risk premium. Dr. Avera's risk-free rate is above current market interest rates. However, the primary problem with his CAPM is his market risk premium of 8.90%. I provide evidence that this market risk premium is based on an expected stock market return that is not reflective of current market fundamentals. I also demonstrate that this expected market return is also based on an expected EPS growth rate that is not reasonable given prospective economic and earnings growth. On the other hand, I use a market risk premium which (1) uses alternative approaches to estimating a market premium and (2) employs the results of over thirty studies and surveys of the market risk premium. As I note, my market risk premium is consistent with the market risk premiums (1) discovered in recent academic studies by leading finance scholars, (2) employed by leading investment banks and management consulting firms, and (3) that result from surveys of financial forecasters and corporate CFOs.

Finally, Dr. Avera's Expected Earnings approach is subject to a number of errors and, therefore, does not provide a reliable estimate of the Company's cost of equity capital. Furthermore, this methodology, which is not market-based, has not been used by regulatory commissions for years as an equity cost rate approach.

In the end, the most significant areas of disagreement between Dr. Avera and me with respect to the cost of equity are: (1) the appropriate DCF growth rate, and (2) the measurement and magnitude of the market risk premium which is used in CAPM approach.

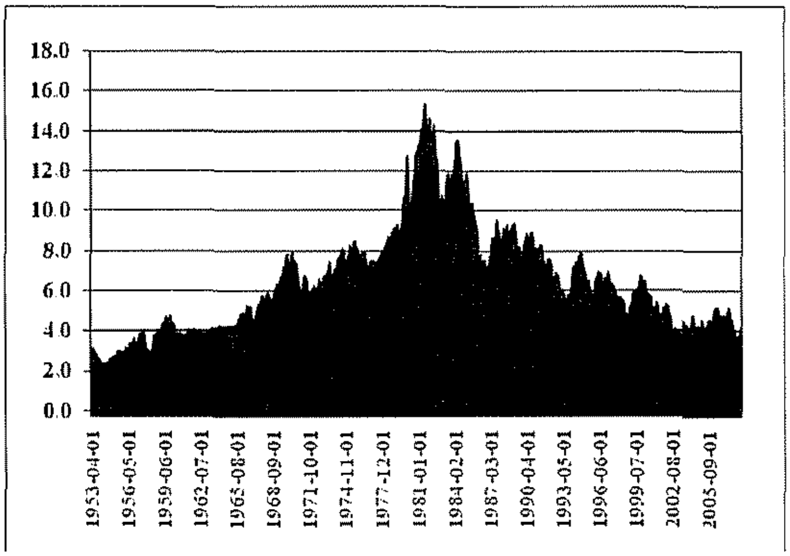
II. CAPITAL COSTS IN TODAY'S MARKETS

Q. PLEASE DISCUSS CAPITAL COSTS IN TODAY'S MARKETS.

A. Long-term capital cost rates for U.S. corporations are currently at their lowest levels in more than four decades. Corporate capital cost rates are determined by the level of interest rates and the risk premium demanded by investors to buy the debt and equity capital of corporate issuers. The base level of long-term interest rates in the U.S. economy is indicated by the rates on ten-year U.S. Treasury bonds. The rates are provided in the graph below from 1953 to the present. As indicated, prior to the decline in rates that began in the year

2000, the 10-year Treasury yield had not consistently been in the 4-5 percent range over an extended period of time since the 1960s.

Yields on Ten-Year Treasury Bonds
1953-Present



Source: http://research.stlouisfed.org/fred2/series/GS10?cid=115

The second base component of the corporate capital cost rates is the risk premium. The risk premium is the return premium required by investors to purchase riskier securities. The equity risk premium is the return premium required to purchase stocks as opposed to bonds. Since the equity risk premium is not readily observable in the markets (as are bond risk premiums), and there are alternative approaches to estimating the equity premium, it is the subject of much debate. One way to estimate the equity risk premium is to compare the mean returns on bonds and stocks over long historical periods. Measured in this manner, the equity risk premium has been in the 5-7 percent range. But recent studies by leading academics indicate the forward-looking equity risk premium is in the 3-4 percent range. These authors indicate that historical equity risk premiums are upwardly biased measures of expected equity risk premiums. Jeremy Siegel, a Wharton finance professor and author of the book *Stocks for the Long Term*, published a study entitled "The Shrinking Equity Risk Premium."[1] He concludes:

> The degree of the equity risk premium calculated from data estimated from 1926 is unlikely to persist in the future. The real return on fixed-income assets is likely to be significantly higher than estimated on earlier data. This is confirmed by the yields available on Treasury index-linked securities, which currently exceed 4%. Furthermore, despite the acceleration in earnings growth, the return on equities is likely to fall from its historical level due to the very high level of equity prices relative to fundamentals.

Alan Greenspan, the former Chairman of the Federal Reserve Board, indicated in an October 14, 1999, speech on financial risk that the fact that equity risk premiums declined during 1990s is "not in dispute." His assessment focused on the relationship between information availability and equity risk premiums.

> There can be little doubt that the dramatic improvements in information technology in recent years have altered our approach to risk. Some analysts perceive that information technology has permanently lowered equity premiums and, hence, permanently raised the prices of the collateral that underlies all financial assets.
>
> The reason, of course, is that information is critical to the evaluation of risk. The less that is known about the current state of a market or a venture, the less the ability to project future outcomes and, hence, the more those potential outcomes will be discounted.

---

[1] Jeremy J. Siegel, "The Shrinking Equity Risk Premium," *The Journal of Portfolio Management* (Fall, 1999), p. 15.

> The rise in the availability of real-time information has reduced the uncertainties and thereby lowered the variances that we employ to guide portfolio decisions. At least part of the observed fall in equity premiums in our economy and others over the past five years does not appear to be the result of ephemeral changes in perceptions. It is presumably the result of a permanent technology-driven increase in information availability, which by definition reduces uncertainty and therefore risk premiums. This decline is most evident in equity risk premiums. It is less clear in the corporate bond market, where relative supplies of corporate and Treasury bonds and other factors we cannot easily identify have outweighed the effects of more readily available information about borrowers.[2]

In sum, the relatively low interest rates in today's markets as well as the lower risk premiums required by investors indicate that capital costs for U.S. companies are low relative to their historic levels.

III. PROXY GROUP SELECTION

Q. PLEASE DESCRIBE YOUR APPROACH TO DEVELOPING A FAIR RATE OF RETURN RECOMMENDATION FOR KU.

A. To develop a fair rate of return recommendation for KU, I have evaluated the return requirements of investors on the common stock of a proxy group of publicly-held electric utility companies.

Q. PLEASE DESCRIBE YOUR PROXY GROUP OF ELECTRIC UTILITY COMPANIES.

---

[2] Alan Greenspan, "Measuring Financial Risk in the Twenty-First Century," Office of the Comptroller of the Currency Conference, October 14, 1999.

A. My Electric Proxy Group proxy group consists of twenty-one electric utility companies. This group includes companies that meet the following criteria: (1) listed as an electric utility or as a combination electric and gas utility by *AUS Utility Reports*, (2) regulated electric revenues must be at least 75% of total revenues; (3) current data available in the Standard Edition of the *Value Line Investment Survey*; (4) an investment grade bond rating; and (5) an annual dividend history of three years. Summary financial statistics for the Electric Proxy are listed in Exhibit JRW-2. The average operating revenues and net plant for the Electric Proxy Group are $5,863.7M and $10,435.4M, respectively. On average, the group receives 89% of revenues from regulated electric utility operations, has a 'Baa1' Moody's bond rating, a common equity ratio of 43%, an earned return on common equity of 10.2%, and sells at a market-to-book ratio of 1.63X.

IV. CAPITAL STRUCTURE RATIOS AND DEBT COST RATES

Q. WHAT IS THE RECOMMENDED CAPITAL STRUCTURE OF THE COMPANY?

A. The Company's recommended capital structure is shown in Panel A of page 1 of Exhibit JRW-3. The Company is requesting a capital structure consisting of 2.70% short-term debt, 44.67% long-term debt, and a 52.63% common equity.

Q. PLEASE DISCUSS THE CAPITAL STRUCTURE YOU ARE USING IN THIS CASE.

A. Mr. Robert Heinkes has developed OAG's capital structure. Whereas Mr. Henkes has made adjustments to the capital amounts, his recommended capital structure ratios are identical to those proposed by the Company. On page 2 of Exhibit JRW-3, I provide the average common equity ratios for the companies in my proxy groups. The average common equity ratio for the Electric Proxy Group is 43.7%. This analysis suggests that the capital structure proposed by the Company and adopted by OAG is very fair to the Company.

Q. ARE YOU ADOPTING THE COMPANY'S SHORT-TERM AND LONG-TERM DEBT COST RATES OF 2.63% AND 5.21%?

A. Yes.

III. THE COST OF COMMON EQUITY CAPITAL

A. Overview

Q. WHY MUST AN OVERALL COST OF CAPITAL OR FAIR RATE OF RETURN BE ESTABLISHED FOR A PUBLIC UTILITY?

A. In a competitive industry, the return on a firm's common equity capital is determined through the competitive market for its goods and services. Due to the capital requirements needed to provide utility services, however and to the economic benefit to society from avoiding duplication of these services, some public utilities are monopolies. It is not appropriate to permit monopoly utilities to set their own prices because of the lack of competition and the essential nature of the services. Thus, regulation seeks to establish prices that are fair to consumers and at the same time are sufficient to meet the operating and capital costs of the utility (i.e., provide an adequate return on capital to attract investors).

Q. PLEASE PROVIDE AN OVERVIEW OF THE COST OF CAPITAL IN THE CONTEXT OF THE THEORY OF THE FIRM.

A. The total cost of operating a business includes the cost of capital. The cost of common equity capital is the expected return on a firm's common stock that the marginal investor would deem sufficient to compensate for risk and the time value of money. In equilibrium, the expected and required rates of return on a company's common stock are equal.

Normative economic models of the firm, developed under very restrictive assumptions, provide insight into the relationship between firm performance or profitability, capital costs, and the value of the firm. Under the economist's ideal model of perfect competition where entry and exit is costless, products are undifferentiated, and there are increasing marginal costs of production, firms produce up to the point where price equals marginal cost. Over time, a long-run equilibrium is established where price equals average cost, including the firm's capital costs. In equilibrium, total revenues equal total costs, and because capital costs represent investors' required return on the firm's capital, actual returns equal required returns and the market value and the book value of the firm's securities must be equal.

In the real world, firms can achieve competitive advantage due to product market imperfections. Most notably, companies can gain competitive advantage through product differentiation (adding real or perceived value to products) and by achieving economies of scale (decreasing marginal costs of production). Competitive advantage allows firms to price products above average cost and thereby earn accounting profits greater than those required to cover capital costs. When these profits are in excess of that required by investors, or when a firm earns a return on equity in excess of its cost of equity, investors respond by valuing the firm's equity in excess of its book value.

James M. McTaggart, founder of the international management consulting firm Marakon Associates, has described this essential relationship between the return on equity, the cost of equity, and the market-to-book ratio in the following manner:[3]

> Fundamentally, the value of a company is determined by the cash flow it generates over time for its owners, and the minimum acceptable rate of return required by capital investors. This "cost of equity capital" is used to discount the expected equity cash flow, converting it to a present value. The cash flow is, in turn, produced by the interaction of a company's return on equity and the annual rate of equity growth. High return on equity (ROE) companies in low-growth markets, such as Kellogg, are prodigious generators of cash flow, while low ROE companies in high-growth markets, such as

[3] James M. McTaggart, "The Ultimate Poison Pill: Closing the Value Gap," *Commentary* (Spring 1988), p. 2.

> Texas Instruments, barely generate enough cash flow to finance growth.
>
> A company's ROE over time, relative to its cost of equity, also determines whether it is worth more or less than its book value. If its ROE is consistently greater than the cost of equity capital (the investor's minimum acceptable return), the business is economically profitable and its market value will exceed book value. If, however, the business earns an ROE consistently less than its cost of equity, it is economically unprofitable and its market value will be less than book value.

As such, the relationship between a firm's return on equity, cost of equity, and market-to-book ratio is relatively straightforward. A firm that earns a return on equity above its cost of equity will see its common stock sell at a price above its book value. Conversely, a firm that earns a return on equity below its cost of equity will see its common stock sell at a price below its book value.

Q. PLEASE PROVIDE ADDITIONAL INSIGHTS INTO THE RELATIONSHIP BETWEEN RETURN ON EQUITY AND MARKET-TO-BOOK RATIOS.

A. This relationship is discussed in a classic Harvard Business School case study entitled "A Note on Value Drivers." On page 2 of that case study, the author describes the relationship very succinctly:[4]

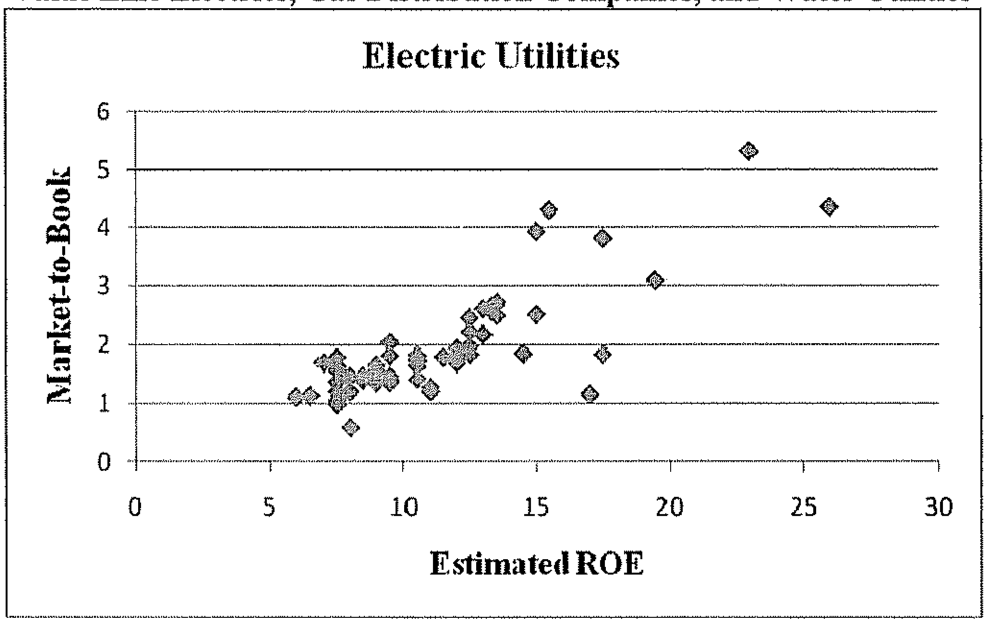
> For a given industry, more profitable firms – those able to generate higher returns per dollar of equity – should have higher market-to-book ratios. Conversely, firms which are unable to generate returns in excess of their cost of equity should sell for less than book value.

[4] Benjamin Esty, "A Note on Value Drivers," Harvard Business School, Case No. 9-297-082, April 7, 1997.

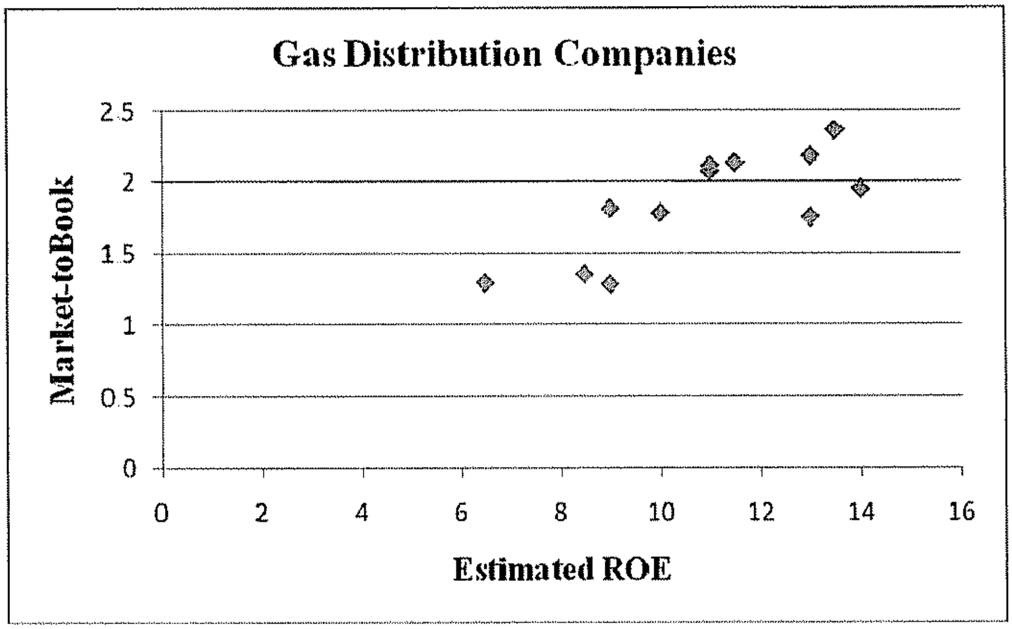
Profitability	*Value*
If ROE > K	*then Market/Book > 1*
If ROE = K	*then Market/Book =1*
If ROE < K	*then Market/Book < 1*

To assess the relationship by industry, as suggested above, I have performed a regression study between estimated return on equity and market-to-book ratios using natural gas distribution, electric utility and water utility companies. I used all companies in these three industries which are covered by *Value Line* and who have estimated return on equity and market-to-book ratio data. The results are presented below.

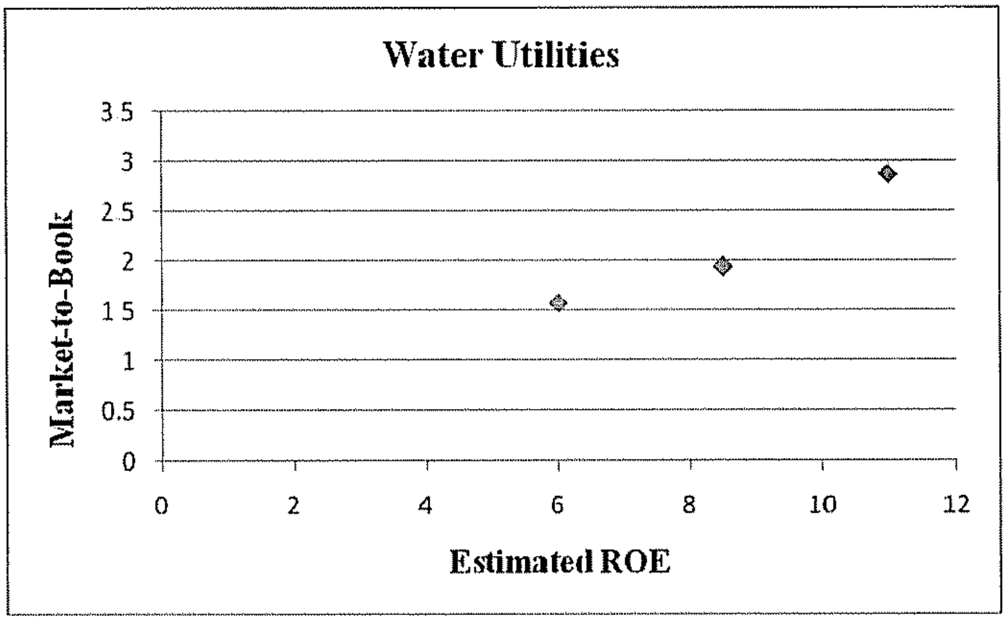
The Relationship Between Estimated ROE and Market-to-Book Ratios
Value Line Electrics, Gas Distribution Companies, and Water Utilities



R-Square = .65
N=56



R-Square = .60
N=12



R-Square = .92
N=4

The average R-squares for the electric, gas, and water companies are 0.65, 0.60, and 0.92.[5] This demonstrates the strong positive relationship between ROEs and market-to-book ratios for public utilities.

Q. WHAT ECONOMIC FACTORS HAVE AFFECTED THE COST OF EQUITY CAPITAL FOR PUBLIC UTILITIES?

A. Exhibit JRW-4 provides indicators of public utility equity cost rates over the past decade. Page 1 shows the yields on 10-year 'A' rated public utility bonds. These yields peaked in the 1990s at 8.5%, then declined and again hit the 8.0 percent range in the year 2000. They subsequently declined, hovering in the 4.5 to 5.0 percent range between 2003 and 2005. They increased to 6.0% in June, of 2006, declined and then once again increased to over 6.0% in the summer of 2007. They retreated to the 5.50% range by the end of 2007. Page 2 provides the dividend yields for the fifteen utilities in the Dow Jones Utilities Average since 1991. These yields peaked in 1994 at 7.2% and have gradually declined over the past decade. As of 2007 these yields and were 3.35%.

Average earned returns on common equity and market-to-book ratios are given on page 3 of Exhibit JRW-4. Over the past decade, earned returns on common equity have consistently been in the 11.0%-13.0% range. The average ROE peaked at 13.45% in 2001 and subsequently declined through

---

[5] R-square measures the percent of variation in one variable (e.g., market-to-book ratios) explained by another variable (e.g., expected return on equity). R-squares vary between zero and 1.0, with values closer to 1.0 indicating a higher relationship between two variables.

the year 2006 before recovering in 2007. Over the past decade, market-to-book ratios for this group have increased gradually but with several ups and downs. The market-to-book average was 1.83 as of 2001, declined to 1.50 in 2003 and increased to 2.2 as of 2007.

The indicators in Exhibit JRW-4, coupled with the overall decrease in interest rates, suggest that capital costs for the Dow Jones Utilities have decreased over the past decade.

Q. WHAT FACTORS DETERMINE INVESTORS' EXPECTED OR REQUIRED RATE OF RETURN ON EQUITY?

A. The expected or required rate of return on common stock is a function of market-wide, as well as company-specific, factors. The most important market factor is the time value of money as indicated by the level of interest rates in the economy. Common stock investor requirements generally increase and decrease with like changes in interest rates. The perceived risk of a firm is the predominant factor that influences investor return requirements on a company-specific basis. A firm's investment risk is often separated into business and financial risk. Business risk encompasses all factors that affect a firm's operating revenues and expenses. Financial risk results from incurring fixed obligations in the form of debt in financing its assets.

Q. HOW DOES THE INVESTMENT RISK OF PUBLIC UTILITY COMPANIES COMPARE WITH THAT OF OTHER INDUSTRIES?

A. Due to the essential nature of their service as well as their regulated status, public utilities are exposed to a lesser degree of business risk than other, non-regulated businesses. The relatively low level of business risk allows public utilities to meet much of their capital requirements through borrowing in the financial markets, thereby incurring greater than average financial risk. Nonetheless, the overall investment risk of public utilities is below most other industries.

Exhibit JRW-5 provides an assessment of investment risk for 100 industries as measured by beta, which according to modern capital market theory is the only relevant measure of investment risk. These betas come from the *Value Line Investment Survey* and are compiled by Aswath Damodoran of New York University.[6] The study shows that the investment risk of public utilities is relatively low. The average beta for electric utilities is 0.88. These figures put electric utility companies in the bottom twenty percent of all industries and well below the *Value Line* average of 1.24. As such, the cost of equity for the electric utilities is among the lowest of all industries in the U.S.

Q. HOW CAN THE EXPECTED OR REQUIRED RATE OF RETURN ON COMMON EQUITY CAPITAL BE DETERMINED?

A. The costs of debt and preferred stock are normally based on historical or book values and can be determined with a great degree of accuracy. The cost of

[6] They may be found on the Internet at http:// www.stern.nyu.edu/~adamodar.

common equity capital, however, cannot be determined precisely and must instead be estimated from market data and informed judgment. This return to the stockholder should be commensurate with returns on investments in other enterprises having comparable risks.

According to valuation principles, the present value of an asset equals the discounted value of its expected future cash flows. Investors discount these expected cash flows at their required rate of return that, as noted above, reflects the time value of money and the perceived riskiness of the expected future cash flows. As such, the cost of common equity is the rate at which investors discount expected cash flows associated with common stock ownership.

Models have been developed to ascertain the cost of common equity capital for a firm. Each model, however, has been developed using restrictive economic assumptions. Consequently, judgment is required in selecting appropriate financial valuation models to estimate a firm's cost of common equity capital, in determining the data inputs for these models, and in interpreting the models' results. All of these decisions must take into consideration the firm involved as well as current conditions in the economy and the financial markets.

Q. HOW DO YOU PLAN TO ESTIMATE THE COST OF EQUITY CAPITAL FOR THE COMPANY?

A. I rely primarily on the DCF model to estimate the cost of equity capital. Given the investment valuation process and the relative stability of the utility business, I believe that the DCF model provides the best measure of equity cost rates for public utilities. It is my experience that this Commission has traditionally relied on the DCF method. I have also performed a CAPM study, but I give these results less weight because I believe that risk premium studies, of which the CAPM is one form, provide a less reliable indication of equity cost rates for public utilities.

B. <u>Discounted Cash Flow Analysis</u>

Q. DESCRIBE THE THEORY BEHIND THE TRADITIONAL DCF MODEL.

A. According to the DCF model, the current stock price is equal to the discounted value of all future dividends that investors expect to receive from investment in the firm. As such, stockholders' returns ultimately result from current as well as future dividends. As owners of a corporation, common stockholders are entitled to a pro-rata share of the firm's earnings. The DCF model presumes that earnings that are not paid out in the form of dividends are reinvested in the firm so as to provide for future growth in earnings and dividends. The rate at which investors discount future dividends, which reflects the timing and riskiness of the expected cash flows, is interpreted as the market's expected or required return on the common stock. Therefore, this discount rate represents the cost of common equity. Algebraically, the DCF model can be expressed as:

$$P = \frac{D_1}{(1+k)^1} + \frac{D_2}{(1+k)^2} + \ldots \frac{D_n}{(1+k)^n}$$

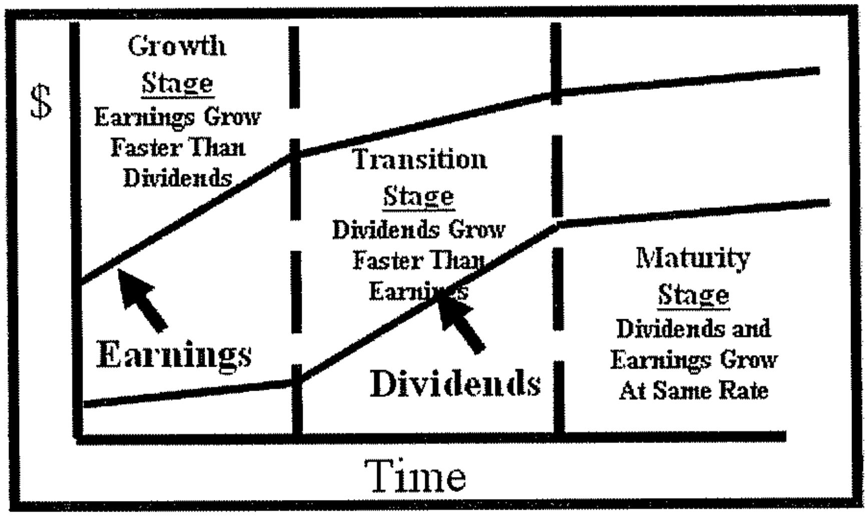
where P is the current stock price, D_n is the dividend in year n, and k is the cost of common equity.

Q. IS THE DCF MODEL CONSISTENT WITH VALUATION TECHNIQUES EMPLOYED BY INVESTMENT FIRMS?

A. Yes. Virtually all investment firms use some form of the DCF model as a valuation technique. One common application for investment firms is called the three-stage DCF or dividend discount model ("DDM"). The stages in a three-stage DCF model are discussed below. This model presumes that a company's dividend payout progresses initially through a growth stage, then proceeds through a transition stage, and finally assumes a steady-state stage. The dividend-payment stage of a firm depends on the profitability of its internal investments, which, in turn, is largely a function of the life cycle of the product or service. These stages are depicted in the graphic below labeled the Three-Stage DCF Model. [7]

[7] This description comes from William F. Sharp, Gordon J. Alexander, and Jeffrey V. Bailey, *Investments* (Prentice-Hall, 1995), pp. 590-91.

Three-Stage DCF Model



1. Growth stage: Characterized by rapidly expanding sales, high profit margins, and abnormally high growth in earnings per share. Because of highly profitable expected investment opportunities, the payout ratio is low. Competitors are attracted by the unusually high earnings, leading to a decline in the growth rate.

2. Transition stage: In later years increased competition reduces profit margins and earnings growth slows. With fewer new investment opportunities, the company begins to pay out a larger percentage of earnings.

3. Maturity (steady-state) stage: Eventually the company reaches a position where its new investment opportunities offer, on average, only slightly attractive returns on equity. At that time its earnings growth rate, payout ratio, and return on equity stabilize for the remainder of its life. The constant-growth DCF model is appropriate when a firm is in the maturity stage of the life cycle.

In using this model to estimate a firm's cost of equity capital, dividends are projected into the future using the different growth rates in the alternative stages, and then the equity cost rate is the discount rate that equates the present value of the future dividends to the current stock price.

Q. HOW DO YOU ESTIMATE STOCKHOLDERS' EXPECTED OR REQUIRED RATE OF RETURN USING THE DCF MODEL?

A. Under certain assumptions, including a constant and infinite expected growth rate, and constant dividend/earnings and price/earnings ratios, the DCF model can be simplified to the following:

$$P = \frac{D_1}{k - g}$$

where D_1 represents the expected dividend over the coming year and g is the expected growth rate of dividends. This is known as the constant-growth version of the DCF model. To use the constant-growth DCF model to estimate a firm's cost of equity, one solves for k in the above expression to obtain the following:

$$k = \frac{D_1}{P} + g$$

Q. IN YOUR OPINION, IS THE CONSTANT-GROWTH DCF MODEL APPROPRIATE FOR PUBLIC UTILITIES?

A. Yes. The economics of the public utility business indicate that the industry is in the steady-state or constant-growth stage of a three-stage DCF. The economics include the relative stability of the utility business, the maturity of the demand for public utility services, and the regulated status of public utilities (especially the fact that their returns on investment are effectively set through the ratemaking process). The DCF valuation procedure for companies in this stage is the constant-growth DCF. In the constant-growth version of the DCF model, the current dividend payment and stock price are directly observable. However, the primary problem and controversy in applying the DCF model to estimate equity cost rates entails estimating investors' expected dividend growth rate.

Q. WHAT FACTORS SHOULD ONE CONSIDER WHEN APPLYING THE DCF METHODOLOGY?

A. One should be sensitive to several factors when using the DCF model to estimate a firm's cost of equity capital. In general, one must recognize the assumptions under which the DCF model was developed in estimating its components (the dividend yield and expected growth rate). The dividend yield can be measured precisely at any point in time, but tends to vary somewhat over time. Estimation of expected growth is considerably more difficult. One must consider recent firm performance, in conjunction with current economic developments and other information available to investors, to accurately estimate investors' expectations.

Q. PLEASE DISCUSS EXHIBIT JRW-6.

A. My DCF analysis is provided in Exhibit JRW-6. The DCF summary is on page 1 of this Exhibit, and the supporting data and analysis for the dividend yield and expected growth rate are provided on the following pages of the Exhibit.

Q. WHAT DIVIDEND YIELDS ARE YOU EMPLOYING IN YOUR DCF ANALYSIS FOR THE PROXY GROUP?

A. The dividend yields on the common stock for the companies in the proxy group are provided on page 2 of Exhibit JRW-6 for the six-month period ending October 2008. For the DCF dividend yields for the group, I am using the average of the six month and October 2008 dividend yields. The table below shows these dividend yields.

Proxy Group	6-Month Average Dividend Yield	October 2008 Dividend Yield	DCF Dividend Yield
Electric Proxy Group	4.4%	4.2%	4.3%

Q. PLEASE DISCUSS THE APPROPRIATE ADJUSTMENT TO THE SPOT DIVIDEND YIELD.

A. According to the traditional DCF model, the dividend yield term relates to the dividend yield over the coming period. As indicated by Professor Myron Gordon, who is commonly associated with the development of the DCF model for popular use, this is obtained by: (1) multiplying the expected dividend over the coming quarter by 4 and (2) dividing this dividend by the current stock price to determine the appropriate dividend yield for a firm, that pays dividends on a quarterly basis.[8]

In applying the DCF model, some analysts adjust the current dividend for growth over the coming year as opposed to the coming quarter. This can be complicated because firms tend to announce changes in dividends at different times during the year. As such, the dividend yield computed based on presumed growth over the coming quarter as opposed to the coming year can be quite different. Consequently, it is common for analysts to adjust the dividend yield by some fraction of the long-term expected growth rate.

Q. GIVEN THIS DISCUSSION, WHAT ADJUSTMENT FACTOR WILL YOU USE FOR YOUR DIVIDEND YIELD?

A. I will adjust the dividend yield by one-half (1/2) the expected growth so as to reflect growth over the coming year.

Q. PLEASE DISCUSS THE GROWTH RATE COMPONENT OF THE DCF MODEL.

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[8] *Petition for Modification of Prescribed Rate of Return*, Federal Communications Commission, Docket No. 79-05, Direct Testimony of Myron J. Gordon and Lawrence I. Gould at 62 (April 1980).

A. There is much debate as to the proper methodology to employ in estimating the growth component of the DCF model. By definition, this component is investors' expectation of the long-term dividend growth rate. Presumably, investors use some combination of historical and/or projected growth rates for earnings and dividends per share and for internal or book value growth to assess long-term potential.

Q. WHAT GROWTH DATA HAVE YOU REVIEWED FOR THE PROXY GROUP?

A. I have analyzed a number of measures of growth for companies in the proxy group. I have reviewed *Value Line's* historical and projected growth rate estimates for earnings per share ("EPS"), dividends per share ("DPS"), and book value per share ("BVPS"). In addition, I have utilized the average EPS growth rate forecasts of Wall Street analysts as provided by Bloomberg and Zacks. These services solicit five-year earnings growth rate projections from securities analysts and compile and publish the means and medians of these forecasts. Finally, I have also assessed prospective growth as measured by prospective earnings retention rates and earned returns on common equity.

Q. PLEASE DISCUSS HISTORICAL GROWTH IN EARNINGS AND DIVIDENDS AS WELL AS INTERNAL GROWTH.

A. Historical growth rates for EPS, DPS, and BVPS are readily available to virtually all investors and presumably an important ingredient in forming expectations concerning future growth. However, one must use historical growth numbers as measures of investors' expectations with caution. In some cases, past growth may not reflect future growth potential. Also, employing a single growth rate number (for example, for five or ten years) is unlikely to accurately measure investors' expectations due to the sensitivity of a single growth rate figure to fluctuations in individual firm performance as well as overall economic fluctuations (i.e., business cycles). However, one must appraise the context in which the growth rate is being employed. According to the conventional DCF model, the expected return on a security is equal to the sum of the dividend yield and the expected long-term growth in dividends. Therefore, to best estimate the cost of common equity capital using the conventional DCF model, one must look to long-term growth rate expectations.

Internally generated growth is a function of the percentage of earnings retained within the firm (the earnings retention rate) and the rate of return earned on those earnings (the return on equity). The internal growth rate is computed as the retention rate times the return on equity. Internal growth is significant in determining long-run earnings and therefore, dividends. Investors recognize the importance of internally generated growth and pay premiums for stocks of companies that retain earnings and earn high returns on internal investments.

Q. WHY ARE YOU NOT RELYING EXCLUSIVELY ON THE EPS

FORECASTS OF WALL STREET ANALYSTS IN ARRIVING AT A DCF GROWTH RATE FOR THE PROXY GROUP?

A. There are several issues with using the EPS growth rate forecasts of Wall Street analysts as DCF growth rates. First, the appropriate growth rate in the DCF model is the dividend growth rate, not the earnings growth rate. Nonetheless, over the very long-term, dividend and earnings will have to grow at a similar growth rate. Therefore, in my opinion, consideration must be given to other indicators of growth, including prospective dividend growth, internal growth, as well as projected earnings growth. Second, and most significantly, it is well-known that the EPS growth rate forecasts of Wall Street securities analysts are overly optimistic and upwardly biased. Hence, using these growth rates as a DCF growth rate will provide an overstated equity cost rate. This issue is discussed at length in the rebuttal section of this testimony.

Q. PLEASE DISCUSS THE HISTORICAL GROWTH OF THE COMPANIES IN THE GROUP AS PROVIDED IN THE *VALUE LINE INVESTMENT SURVEY*.

A. Historic growth rates for the companies in the group, as published in the *Value Line Investment Survey*, are provided on page 3 of Exhibit JRW-6. Due to the presence of outliers among the historic growth rate figures, both the mean and medians are used in the analysis.[9] The historical growth measures in EPS,

[9] Outliers are observations that are much larger or smaller than the majority of the observations that are being evaluated

DPS, and BVPS for the Electric Proxy Group, as measured by the means and medians, range from -0.8% to 4.0%, with an average of 1.7%.

Q. PLEASE SUMMARIZE *VALUE LINE'S* PROJECTED GROWTH RATES FOR THE COMPANIES IN THE PROXY GROUP.

A. *Value Line's* projections of EPS, DPS, and BVPS growth for the companies in the proxy group are shown on page 4 of Exhibit JRW-6. As above, due to the presence of outliers, both the mean and medians are used in the analysis. For the Electric Proxy Group, the central tendency measures range from 4.0% to 7.5%, with an average of 5.2%.

Also provided on page 4 of Exhibit JRW-6 is prospective internal growth for the proxy group as measured by *Value Line*'s average projected retention rate and return on shareholders' equity. As noted above, internal growth is significant in a primary driver of long-run earnings growth. For the Electric Proxy Group, the average prospective internal growth rate is 4.0%.

Q. PLEASE ASSESS GROWTH FOR THE PROXY GROUP AS MEASURED BY ANALYSTS' FORECASTS OF EXPECTED 5-YEAR EPS GROWTH.

A. Zacks and Bloomberg collect, summarize, and publish Wall Street analysts' five-year EPS growth rate forecasts for the companies in the proxy group. These forecasts are provided for the companies in the proxy group on page 5 of Exhibit JRW-6. The median of the analysts' projected EPS growth rates for the Electric Proxy Group is 6.25%.[10]

Q. PLEASE SUMMARIZE YOUR ANALYSIS OF THE HISTORICAL AND PROSPECTIVE GROWTH OF THE PROXY GROUP.

A. The table below shows the summary DCF growth rate indicators for the proxy group.

DCF Growth Rate Indicators

Growth Rate Indicator	Electric Proxy Group
Historic *Value Line* Growth in EPS, DPS, and BVPS	**1.7%**
Projected *Value Line* Growth in EPS, DPS, and BVPS	**5.2%**
Internal Growth ROE * Retention rate	**4.0%**
Projected EPS Growth from Bloomberg and Zacks	**6.25%**

The average of the growth rate indicators for the Electric Proxy Group is 4.3%. Giving greater weight to the projected growth rate indicators and to prospective internal growth, an expected DCF growth rate in the 5.0%-6.0% range is reasonable for the group. I will use the midpoint of this range, 5.5%, as the DCF growth rate for the Electric Proxy Group.

[10] Since there is considerable overlap in analyst coverage between the three services, and not all of the companies have forecasts from the different services, I have averaged the expected five-year EPS growth rates from the three services for each company to arrive at an expected EPS growth rate by company.

Q. BASED ON THE ABOVE ANALYSIS, WHAT IS YOUR INDICATED COMMON EQUITY COST RATES FROM THE DCF MODEL FOR THE PROXY GROUP?

A. My DCF-derived equity cost rate for the group is:

$$\text{DCF Equity Cost Rate (k)} = \frac{D}{P} + g$$

DCF Equity Cost Rate

	Electric Proxy Group
Dividend Yield	**4.3%**
1 + (½ Growth Rate Adjustment)	**1.0275**
DCF Growth Rate	**5.50%**
Equity Cost Rate	**9.9%**

These results are summarized on page 1 of Exhibit JRW-6.

C. Capital Asset Pricing Model Results

Q. PLEASE DISCUSS THE CAPITAL ASSET PRICING MODEL ("CAPM").

A. The CAPM is a risk premium approach to gauging a firm's cost of equity capital. According to the risk premium approach, the cost of equity is the sum of the interest rate on a risk-free bond (R_f) and a risk premium (RP), as in the following:

$$k \quad = \quad R_f \quad + \quad RP$$

The yield on long-term Treasury securities is normally used as R_f. Risk premiums are measured in different ways. The CAPM is a theory of the risk and expected returns of common stocks. In the CAPM, two types of risk are associated with a stock: firm-specific risk or unsystematic risk, and market or systematic risk, which is measured by a firm's beta. The only risk that investors receive a return for bearing is systematic risk.

According to the CAPM, the expected return on a company's stock, which is also the equity cost rate (K), is equal to:

$$K = (R_f) + ß * [E(R_m) - (R_f)]$$

Where:

- K represents the estimated rate of return on the stock;
- $E(R_m)$ represents the expected return on the overall stock market. Frequently, the 'market' refers to the S&P 500;
- (R_f) represents the risk-free rate of interest;
- $[E(R_m) - (R_f)]$ represents the expected equity or market risk premium—the excess return that an investor expects to receive above the risk-free rate for investing in risky stocks; and
- *Beta*—(ß) is a measure of the systematic risk of an asset.

To estimate the required return or cost of equity using the CAPM requires three inputs: the risk-free rate of interest (R_f), the beta (ß), and the expected equity or market risk premium $[E(R_m) - (R_f)]$. R_f is the easiest of the inputs to measure – it is the yield on long-term Treasury bonds. ß, the measure of systematic risk, is a little more difficult to measure because there are different opinions about what adjustments, if any, should be made to historical betas due to their tendency to regress to 1.0 over time. And finally, an even more difficult input to measure is the expected equity or market risk premium $(E(R_m) - (R_f))$. I will discuss each of these inputs below.

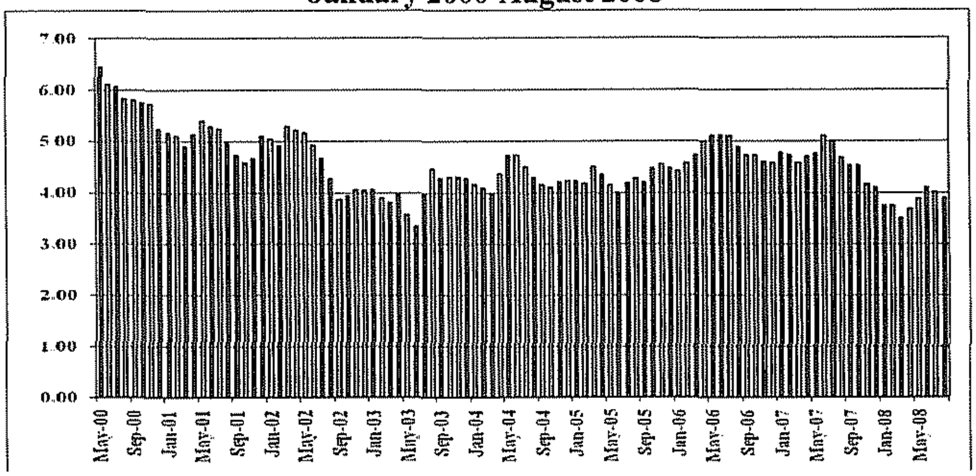
Q. PLEASE DISCUSS EXHIBIT JRW-7.

A. Exhibit JRW-7 provides the summary results for my CAPM study. Page 1 shows the results, and pages 2-5 contain the supporting data.

Q. PLEASE DISCUSS THE RISK-FREE INTEREST RATE.

A. The yield on long-term U.S. Treasury bonds has usually been viewed as the risk-free rate of interest in the CAPM. The yield on long-term U.S. Treasury bonds, in turn, has been considered to be the yield on U.S. Treasury bonds with 30-year maturities. However, when the Treasury's issuance of 30-year bonds was interrupted for a period of time in recent years, the yield on 10-year U.S. Treasury bonds replaced the yield on 30-year U.S. Treasury bonds as the benchmark long-term Treasury rate. The 10-year U.S. Treasury yields over the past five years are shown in the chart below. These rates hit a 60-year low in the summer of 2003 at 3.33%. They increased with the rebounding economy and fluctuated in the 4.0-4.50 percent range in recent years until advancing to 5.0% in early 2006 in response to a strong economy and increases in energy, commodity, and consumer prices. In late 2006, long-term interest rates retreated to the 4.5 percent area as commodity and energy prices declined and inflationary pressures subsided. These rates rebounded to the 5.0% level in the first half of 2007. However, ten-year Treasury yields have again fall below 4.0 percent due to the housing and sub-prime mortgage crises and its affect on the economy and financial markets.

Ten-Year U.S. Treasury Yields
January 2000-August 2008



http://research.stlouisfed.org/fred2/series/GS10?cid=115

Q. WHAT RISK-FREE INTEREST RATE ARE YOU USING IN YOUR CAPM?

A. The U.S. Treasury began to issue the 30-year bond in the early 2000s as the U.S. budget deficit increased. As such, the market has once again focused on its yield as the benchmark for long-term capital costs in the U.S. As noted above, the yields on the 10- and 30- year U.S. Treasuries decreased to below 5.0% in 2007 and have remained at these lower levels. In 2008 Treasury yields have been pushed even lower as a result of the mortgage and sub-prime market credit crisis, the turmoil in the financial sector, the prospect of an economic recession, and the government bailout of financial institutions. As of September 22, 2008, as shown in the table below, the rates on 10- and 30- U.S. Treasury Bonds were 3.67% and 4.16%, respectively. However, these yields have been highly volatile over the past two months. Given this recent range and volatility, along with the prospect of higher rates, I will use 4.5% as the risk-free rate, or R_f, in my CAPM.

U.S. Treasury Yields
October 2, 2008

U.S. Treasuries

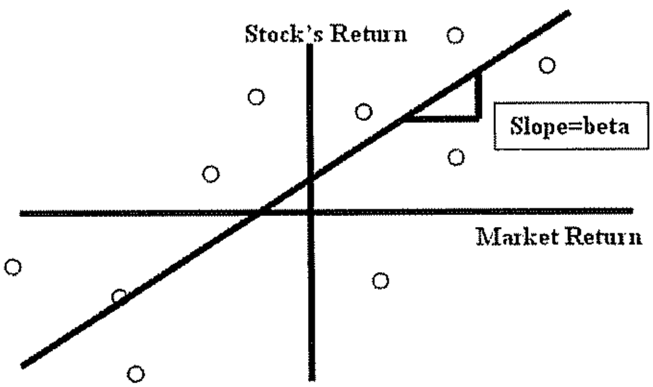
	COUPON	MATURITY DATE	CURRENT PRICE/YIELD
3-MONTH	0.000	01/02/2009	0.67 / .68
6-MONTH	0.000	04/02/2009	1.2 / 1.22
12-MONTH	0.000	09/24/2009	1.42 / 1.46
2-YEAR	2.000	09/30/2010	101-12+ / 1.66
3-YEAR	4.500	09/30/2011	107-10+ / 1.97
5-YEAR	3.125	09/30/2013	101-25+ / 2.73
10-YEAR	4.000	08/15/2018	102-22+ / 3.67
30-YEAR	4.500	05/15/2038	105-25+ / 4.16

Source: www.bloomberg.com

Q. WHAT BETA ARE YOU EMPLOYING IN YOUR CAPM?

A. Beta (ß) is a measure of the systematic risk of a stock. The market, usually taken to be the S&P 500, has a beta of 1.0. The beta of a stock with the same price movement as the market also has a beta of 1.0. A stock whose price movement is greater than that of the market, such as a technology stock, is riskier than the market and has a beta greater than 1.0. A stock with below average price movement, such as that of a regulated public utility, is less risky than the market and has a beta less than 1.0. Estimating a stock's beta involves running a linear regression of a stock's return on the market return as in the following:

Calculation of Beta



The slope of the regression line is the stock's ß. A steeper line indicates the stock is more sensitive to the return on the overall market. This means that the stock has a higher ß and greater than average market risk. A less steep line indicates a lower ß and less market risk.

Numerous online investment information services, such as Yahoo! and Reuters, provide estimates of stock betas. Usually these services report different betas for the same stock. The differences are usually due to: (1) the time period over which the ß is measured; and (2) any adjustments that are made to reflect the fact that betas tend to regress to 1.0 over time. In estimating an equity cost rate for the proxy group, I am using the betas for the companies as provided in the *Value Line Investment Survey*. As shown on page 2 of Exhibit JRW-7, the average beta for the companies in the Electric Proxy Group is 0.82.

Q. PLEASE DISCUSS THE OPPOSING VIEWS REGARDING THE EQUITY RISK PREMIUM.

A. The equity or market risk premium - $(E(R_m) - R_f)$ - is equal to the expected return on the stock market (e.g., the expected return on the S&P 500 ($E(R_m)$) minus the risk-free rate of interest (R_f). The equity premium is the difference in the expected total return between investing in equities and investing in "safe" fixed-income assets, such as long-term government bonds. However, while the equity risk premium is easy to define conceptually, it is difficult to measure because it requires an estimate of the expected return on the market.

Q. PLEASE DISCUSS THE ALTERNATIVE APPROACHES TO ESTIMATING THE EQUITY RISK PREMIUM.

A. The table below highlights the primary approaches to, and issues in, estimating the expected equity risk premium. The traditional way to measure the equity risk premium was to use the difference between historical average stock and bond returns. In this case, historical stock and bond returns, also called ex post returns, were used as the measures of the market's expected return (known as the ex ante or forward-looking expected return). This type of historical evaluation of stock and bond returns is often called the "Ibbotson approach" after Professor Roger Ibbotson who popularized this method of using historical financial market returns as measures of expected returns. Most historical assessments of the equity risk premium suggest an equity risk premium of 5-7 percent above the rate on long-term U.S. Treasury bonds. However, this can be a problem because: (1) ex post returns are not the same as ex ante expectations, (2) market risk premiums can change over time;

increasing when investors become more risk-averse and decreasing when investors become less risk-averse, and (3) market conditions can change such that ex post historical returns are poor estimates of ex ante expectations.

Risk Premium Approaches

	Historical Ex Post Excess Returns	Surveys	Ex Ante Models and Market Data
Means of Assessing the Equity-Bond Risk Premium	Historical average is a popular proxy for the ex ante premium – but likely to be misleading	Investor and expert surveys can provide direct estimates of prevailing expected returns/premiums	Current financial market prices (simple valuation ratios or DCF-based measures) can give most objective estimates of feasible ex ante equity-bond risk premium
Problems/Debated Issues	Time variation in required returns and systematic selection and other biases have boosted valuations over time, and have exaggerated realized excess equity returns compared with ex ante expected premiums	Limited survey histories and questions of survey representativeness. Surveys may tell more about hoped-for expected returns than about objective required premiums due to irrational biases such as extrapolation.	Assumptions needed for DCF inputs, notably the trend earnings growth rate, make even these models' outputs subjective. The range of views on the growth rate, as well as the debate on the relevant stock and bond yields, leads to a range of premium estimates.

Source: Antti Ilmanen, Expected Returns on Stocks and Bonds," *Journal of Portfolio Management*, (Winter 2003).

The use of historical returns as market expectations has been criticized in numerous academic studies.[11] The general theme of these studies is that the large equity risk premium discovered in historical stock and bond returns cannot be justified by the fundamental data. These studies, which fall under the category "Ex Ante Models and Market Data," compute ex ante expected returns using market data to arrive at an expected equity risk premium. These studies have also been called "Puzzle Research" after the famous study by Mehra and Prescott in which the authors first questioned the magnitude of historical equity risk premiums relative to fundamentals.[12]

[11] The problems with using ex post historical returns as measures of ex ante expectations will be discussed at length later in my testimony.

[12] R. Mehra and Edward Prescott, "The Equity Premium: A Puzzle," *Journal of Monetary Economics* (1985).

Q. PLEASE SUMMARIZE SOME OF THE ACADEMIC STUDIES THAT DEVELOP EX ANTE EQUITY RISK PREMIUMS.

A. Two of the most prominent studies of ex ante expected equity risk premiums were by Eugene Fama and Ken French (2002) and James Claus and Jacob Thomas (2001). The primary debate in these studies revolves around two related issues: (1) the size of expected equity risk premium, which is the return equity investors require above the yield on bonds and (2) the fact that estimates of the ex ante expected equity risk premium using fundamental firm data (earnings and dividends) are much lower than estimates using historical stock and bond return data.

Fama and French (2002), two of the most preeminent scholars in finance, use dividend and earnings growth models to estimate expected stock returns and ex ante expected equity risk premiums.[13] They compare these results to actual stock returns over the period 1951-2000. Fama and French estimate that the expected equity risk premium from DCF models using dividend and earnings growth to be between 2.55% and 4.32%. These figures are much lower than the ex post historical equity risk premium produced from the average stock and bond return over the same period, which is 7.40%. Fama and French conclude that the ex ante equity risk premium estimates using DCF models and fundamental data are superior to those using ex post historical stock returns for three reasons: (1) the estimates are more precise (a lower standard error); (2) the Sharpe ratio, which is measured as the

[13] Eugene F. Fama and Kenneth R. French, "The Equity Premium," *The Journal of Finance*, (April 2002).

[(expected stock return – risk-free rate)/standard deviation], is constant over time for the DCF models but varies considerably over time and more than doubles for the average stock-bond return model; and (3) valuation theory specifies relationships between the market-to-book ratio, return on investment, and cost of equity capital that favor estimates from fundamentals. They also conclude that the high average stock returns over the past 50 years were the result of low expected returns and that the average equity risk premium has been in the 3-4 percent range.

The study by Claus and Thomas of Columbia University provides direct support for the findings of Fama and French.[14] These authors compute ex ante expected equity risk premiums over the 1985-1998 period by: (1) computing the discount rate that equates market values with the present value of expected future cash flows and (2) then subtracting the risk-free interest rate. The expected cash flows are developed using analysts' earnings forecasts. The authors conclude that over this period, the ex ante expected equity risk premium is in the range of 3.0%. Claus and Thomas note that, over this period, ex post historical stock returns overstate the ex ante expected equity risk premium because, as the expected equity risk premium has declined, stock prices have risen. In other words, from a valuation perspective, the present value of expected future returns increase when the required rate of return decreases. The higher stock prices have produced stock

[14] James Claus and Jacob Thomas, "Equity Risk Premia as Low as Three Percent? Empirical Evidence from Analysts' Earnings Forecasts for Domestic and International Stock Market," *Journal of Finance.* (October 2001).

returns that have exceeded investors' expectations, and therefore, ex post historical equity risk premium estimates are biased upwards as measures of ex ante expected equity risk premiums.

Q. PLEASE PROVIDE A SUMMARY OF THE EQUITY RISK PREMIUM STUDIES.

A. Derrig and Orr (2003), Fernandez (2007), and Song (2007) have completed the most comprehensive reviews to date of the research on the equity risk premium.[15] Derrig and Orr's study evaluated the various approaches to estimating equity risk premiums as well as the issues with the alternative approaches and summarized the findings of the published research on the equity risk premium. Fernandez examined four alternative measures of the equity risk premium – historical, expected, required, and implied. He also reviewed the major studies of the equity risk premium and presented the summary equity risk premium results. Song provides an annotated bibliography and highlights the alternative approaches to estimating the equity risk summary.

Page 3 of Exhibit JRW-7 provides a summary of the results of the primary risk premium studies reviewed by Derrig and Orr, Fernandez, and Song. In developing page 3 of Exhibit JRW-7, I have categorized the studies as discussed on page 39 of my testimony. I have also included the results of

[15] Richard Derrig and Elisha Orr, "Equity Risk Premium: Expectations Great and Small," Working Paper (version 3.0), Automobile Insurers Bureau of Massachusetts, (August 28, 2003), Pablo Fernandez, "Equity Premium: Historical, Expected, Required, and Implied," IESE Business School Working Paper, (2007), and Zhiyi Song, "The Equity Risk Premium: An Annotated Bibliography," CFA Institute, (2007).

the "Building Blocks" approach to estimating the equity risk premium, including a study I performed, which is presented below. The Building Blocks approach is a hybrid approach employing elements of both historic and ex ante models.

Q. PLEASE DISCUSS YOUR DEVELOPMENT OF AN EQUITY RISK PREMIUM COMPUTED USING THE BUILDING BLOCKS METHODOLOGY.

A. Ibbotson and Chen (2003) evaluate the ex post historical mean stock and bond returns in what is called the Building Blocks approach.[16] They use 75 years of data and relate the compounded historical returns to the different fundamental variables employed by different researchers in building ex ante expected equity risk premiums. Among the variables included were inflation, real EPS and DPS growth, ROE and book value growth, and price-earnings ("P/E") ratios. By relating the fundamental factors to the ex post historical returns, the methodology bridges the gap between the ex post and ex ante equity risk premiums. Ilmanen (2003) illustrates this approach using the geometric returns and five fundamental variables – inflation ("CPI"), dividend yield ("D/P"), real earnings growth ("RG"), repricing gains ("PEGAIN") and return interaction/reinvestment ("INT").[17] This is shown in the graph below. The first column breaks the 1926-2000 geometric mean stock return of 10.7% into

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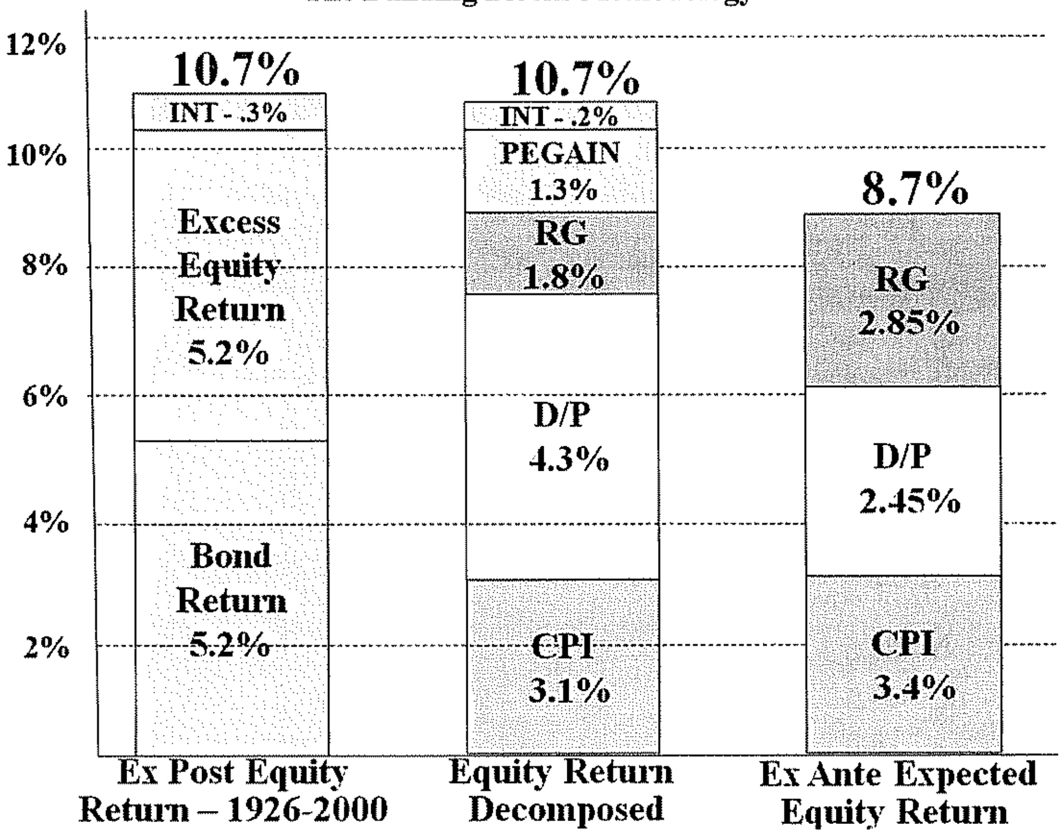
[16] Roger Ibbotson and Peng Chen, "Long Run Returns: Participating in the Real Economy," *Financial Analysts Journal*, (January 2003).

[17] Antti Ilmanen, Expected Returns on Stocks and Bonds," *Journal of Portfolio Management*, (Winter 2003), p. 11.

the different return components demanded by investors: the historical U.S. Treasury bond return (5.2%), the excess equity return (5.2%), and a small interaction term (0.3%). This 10.7% annual stock return over the 1926-2000 period can then be broken down into the following fundamental elements: inflation (3.1%), dividend yield (4.3%), real earnings growth (1.8%), repricing gains (1.3%) associated with higher P/E ratios, and a small interaction term (0.2%).

Decomposing Equity Market Returns
The Building Blocks Methodology

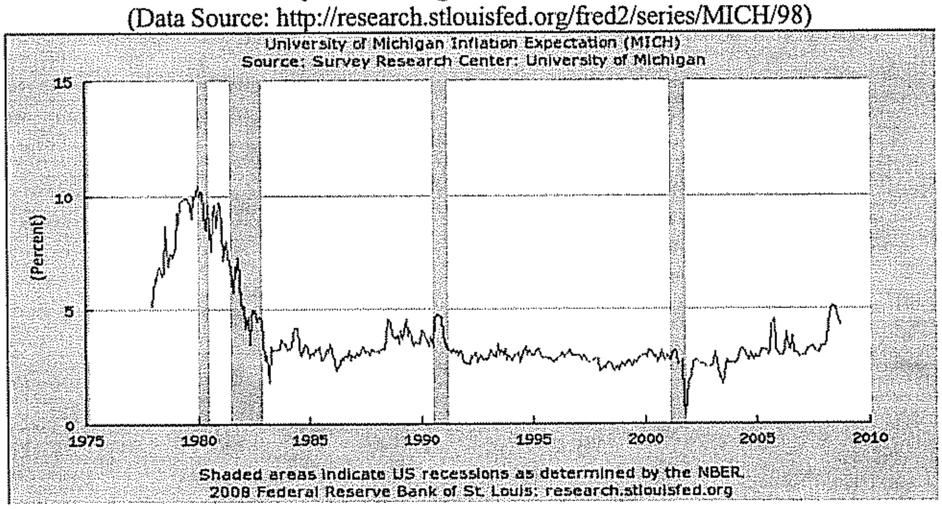


Q. HOW ARE YOU USING THIS METHODOLOGY TO DERIVE AN EX ANTE EXPECTED EQUITY RISK PREMIUM?

A. The third column in the graph above shows current inputs to estimate an ex ante expected market return. These inputs include the following:

CPI – To assess expected inflation, I have employed expectations of the short-term and long-term inflation rate. The graph below shows the expected annual inflation rate according to consumers, as measured by the CPI, over the coming year. This survey is published monthly by the University of Michigan Survey Research Center. In the most recent report, the expected one-year inflation rate was 4.3%.

Expected Inflation Rate
University of Michigan Consumer Research
(Data Source: http://research.stlouisfed.org/fred2/series/MICH/98)



Longer term inflation forecasts are available in the Federal Reserve Bank of Philadelphia's publication entitled *Survey of Professional Forecasters*.[18] This survey of professional economists has been published for almost 50 years. While this survey is published quarterly, only the first

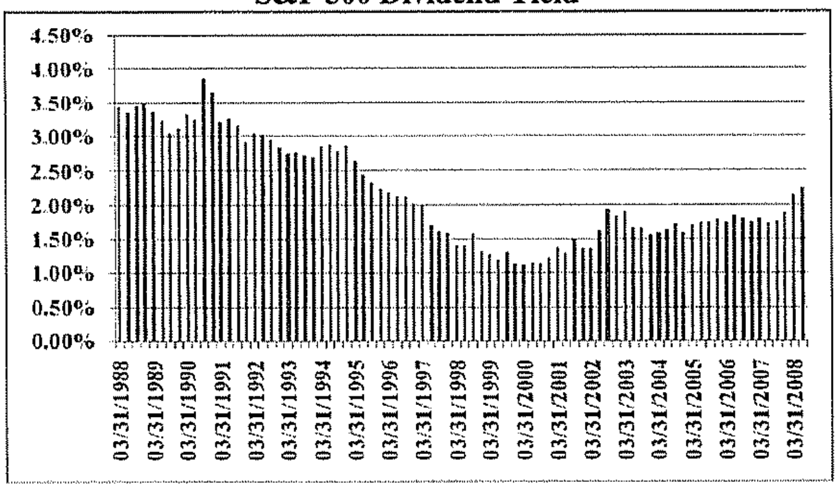
[18]Federal Reserve Bank of Philadelphia, *Survey of Professional Forecasters*, (February 12, 2008). The *Survey of Professional Forecasters* was formerly conducted by the American Statistical Association ("ASA") and the National Bureau of Economic Research ("NBER") and was known as the ASA/NBER survey. The survey, which began in 1968, is conducted each quarter. The Federal Reserve Bank of Philadelphia, in cooperation with the NBER, assumed responsibility for the survey in June 1990.

quarter survey includes long-term forecasts of gross domestic product ("GDP") growth, inflation, and market returns. In the first quarter 2008 survey, published on February 12, 2008, the median long-term (10-year) expected inflation rate as measured by the CPI was 2.5% (see page 4 of Exhibit JRW-7).

Given these results, I will use the average of the surveys of the University of Michigan and Federal Reserve Bank of Philadelphia (4.3% and 2.5%), or 3.4%.

D/P – As shown in the graph below, the dividend yield on the S&P 500 has decreased gradually over the past decade. Today, it is far below its average of 4.3% over the 1926-2000 time period. Whereas the S&P dividend yield bottomed out at less than 1.4% in 2000, it is currently at 2.45% which I use in the ex ante risk premium analysis.

S&P 500 Dividend Yield



RG – To measure expected real growth in earnings, I use: (1) the historical real earnings growth rate for the S&P 500 and (2) expected real GDP growth.

The S&P 500 was created in 1960. It includes 500 companies which come from ten different sectors of the economy. Over the 1960-2007 period, nominal growth in EPS for the S&P 500 was 7.36%. On page 5 of Exhibit JRW-7, real EPS growth is computed using the CPI as a measure of inflation. As indicated by Ibbotson and Chen, real earnings growth over the 1926-2000 period was 1.8%. The real growth figure over 1960-2007 period for the S&P 500 is 3.0 %.

The second input for expected real earnings growth is expected real GDP growth. The rationale is that over the long-term, corporate profits have averaged a relatively consistent 5.50% of U.S. GDP.[19] Real GDP growth, according to McKinsey, has averaged 3.5% over the past 80 years. Expected GDP growth, according to the Federal Reserve Bank of Philadelphia's *Survey of Professional Forecasters,* is 2.75% (see page 4 of Exhibit JRW-7).

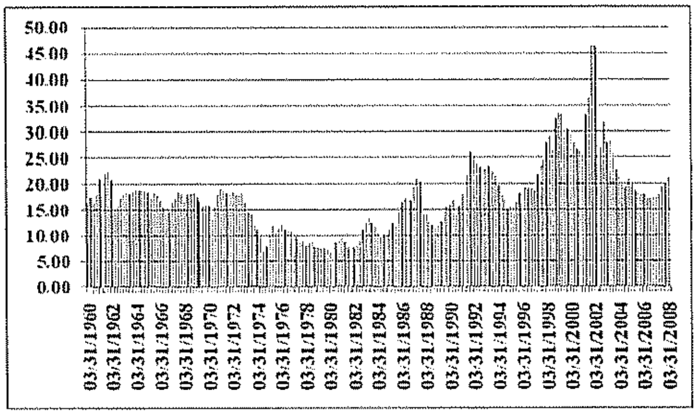
Given these results, I will use the average of the historical S&P EPS real growth and the projected real GDP growth (as reported by the Federal Reserve Bank of Philadelphia Survey) -- 3.0% and 2.75% -- or 2.85%, for real earnings growth.

PEGAIN – PEGAIN is the repricing gain associated with an increase in the P/E ratio. It accounted for 1.3% of the 10.7% annual stock return in the 1926-2000 period. In estimating an ex ante expected stock market return, one issue is whether investors expect P/E ratios to increase from their current levels. The graph below shows the P/E ratios for the S&P 500 over the past

[19]Marc. H. Goedhart, et al, "The Real Cost of Equity," *McKinsey on Finance* (Autumn 2002), p.14.

25 years. The run-up and eventual peak in P/Es is most notable in the chart. The relatively low P/E ratios (in the range of 10) over two decades ago are also quite notable. As of September 30, 2008, the P/E for the S&P 500 was 22.5.[20]

S&P 500 PE Ratios



Given the current economic and capital markets environment, I do not believe that investors expect even higher P/E ratios. Therefore, a PEGAIN would not be appropriate in estimating an ex ante expected stock market return. There are two primary reasons for this. First, the average historical S&P 500 P/E ratio is 15.74 – thus the current P/E exceeds this figure. Second, as previously noted, interest rates are at a cyclical low not seen in almost 50 years. This is a primary reason for the high current P/Es. Given the current market environment with relatively high P/E ratios and low relative interest rates, investors are not likely to expect to get stock market gains from lower interest rates and higher P/E ratios.

[20] Source: www.standardandpoors.com.

Q. GIVEN THIS DISCUSSION, WHAT IS YOUR EX ANTE EXPECTED MARKET RETURN AND EQUITY RISK PREMIUM USING THE "BUILDING BLOCKS METHODOLOGY"?

A. My expected market return is represented by the last column on the right in the graph entitled "Decomposing Equity Market Returns: The Building Blocks Methodology" set forth on page 44 of my testimony. As shown, my expected market return of 8.7% is composed of 3.40% expected inflation, 2.45% dividend yield, and 2.85% real earnings growth rate.

Q. GIVEN THAT THE HISTORICAL COMPOUNDED ANNUAL MARKET RETURN IS IN EXCESS OF 10%, WHY DO YOU BELIEVE THAT YOUR EXPECTED MARKET RETURN OF 8.7% IS REASONABLE?

A. As discussed above, in the development of the expected market return, stock prices are relatively high at the present time in relation to earnings and dividends, and interest rates are relatively low. Hence, it is unlikely that investors are going to experience high stock market returns due to higher P/E ratios and/or lower interest rates. In addition, as shown in the decomposition of equity market returns, whereas the dividend portion of the return was historically 4.3%, the current dividend yield is only 2.45%. Due to these reasons, lower market returns are expected for the future.

Q. IS YOUR EXPECTED MARKET RETURN OF 8.7% CONSISTENT WITH THE FORECASTS OF MARKET PROFESSIONALS?

A. Yes. In the first quarter 2008 *Survey of Financial Forecasters*, published on February 12, 2008 by the Federal Reserve Bank of Philadelphia, the mean long-term expected return on the S&P 500 was 6.8% (see page 4 of Exhibit JRW-7). This is consistent with my expected market return of 8.7%.

Q. IS YOUR EXPECTED MARKET RETURN CONSISTENT WITH THE EXPECTED MARKET RETURNS OF CORPORATE CHIEF FINANCIAL OFFICERS (CFOS)?

A. Yes. John Graham and Campbell Harvey of Duke University conduct a quarterly survey of corporate CFOs. The survey is a joint project of Duke University and *CFO Magazine*. In the third quarter 2008 survey, the mean expected return on the S&P 500 over the next ten years was 7.79%.[21]

Q. GIVEN THIS EXPECTED MARKET RETURN, WHAT IS YOUR EX ANTE EQUITY RISK PREMIUM USING THE BUILDING BLOCKS METHODOLOGY?

A. As shown on page 36, the current 30-year U.S. Treasury yield is 4.16%. My ex ante equity risk premium is simply the expected market return from the Building Blocks methodology minus this risk-free rate:

Ex Ante Equity Risk Premium = 8.70% - 4.16% = 4.54%

[21] The survey results are available at www.cfosurvey.org.

Q. GIVEN THIS DISCUSSION, HOW ARE YOU MEASURING AN EXPECTED EQUITY RISK PREMIUM IN THIS PROCEEDING?

A. As discussed above, page 3 of Exhibit JRW-7 provides a summary of the results of the equity risk premium studies that I have reviewed. These include the results of: (1) the various studies of the historical risk premium, (2) ex ante equity risk premium studies, (3) equity risk premium surveys of CFOs, Financial Forecasters, and academics, and (4) the Building Block approaches to the equity risk premium. There are results reported for over thirty studies, and the average equity risk premium is 4.56%, which I will use as the equity risk premium in my CAPM study.

Q. IS YOUR EX ANTE EQUITY RISK PREMIUM CONSISTENT WITH THE EQUITY RISK PREMIUMS OF LEADING INVESTMENT FIRMS?

A. Yes. One of the first studies in this area was by Stephen Einhorn, one of Wall Street's leading investment strategists.[22] His study showed that the market or equity risk premium had declined to the 2.0 - 3.0 percent range by the early 1990s. Among the evidence he provided in support of a lower equity risk premium is the inverse relationship between real interest rates (observed interest rates minus inflation) and stock prices. He noted that the decline in the market risk premium has led to a significant change in the relationship between interest rates and stock prices. One implication of this development

[22] Steven G. Einhorn, "The Perplexing Issue of Valuation: Will the Real Value Please Stand Up?" *Financial Analysts Journal* (July-August 1990), pp. 11-16.

was that stock prices had increased higher than would be suggested by the historical relationship between valuation levels and interest rates.

The equity risk premiums of some of the other leading investment firms today support the result of the academic studies. An article in *The Economist* indicated that some other firms like J.P. Morgan are estimating an equity risk premium for an average risk stock in the 2.0 - 3.0 percent range above the interest rate on U.S. Treasury Bonds.[23]

Q. IS YOUR EX ANTE EQUITY RISK PREMIUM CONSISTENT WITH THE EQUITY RISK PREMIUMS USED BY CFOS?

A. Yes. In the previously referenced third quarter 2008 CFO survey conducted by *CFO Magazine* and Duke University, the expected 10-year equity risk premium was 3.99%.

Q. IS YOUR EX ANTE EQUITY RISK PREMIUM CONSISTENT WITH THE EX ANTE EQUITY RISK PREMIUMS OF PROFESSIONAL FORECASTERS?

A. Yes. The financial forecasters in the previously referenced Federal Reserve Bank of Philadelphia survey project both stock and bond returns. As shown on page 4 of Exhibit JRW-7, the mean long-term expected stock and bond returns were 6.80% and 4.84%, respectively. This provides an ex ante equity risk premium of 1.96%.

[23] For example, see "Welcome to Bull Country," *The Economist* (July 18, 1998), pp. 21-3, and "Choosing the Right Mixture," *The Economist* (February 27, 1999), pp 71-2.

Q. IS YOUR EX ANTE EQUITY RISK PREMIUM CONSISTENT WITH THE EQUITY RISK PREMIUMS USED BY THE LEADING CONSULTING FIRMS?

A. Yes. McKinsey & Co. is widely recognized as the leading management consulting firm in the world. It published a study entitled "The Real Cost of Equity" in which the McKinsey authors developed an ex ante equity risk premium for the U.S. In reference to the decline in the equity risk premium, as well as what is the appropriate equity risk premium to employ for corporate valuation purposes, the McKinsey authors concluded the following:

> We attribute this decline not to equities becoming less risky (the inflation-adjusted cost of equity has not changed) but to investors demanding higher returns in real terms on government bonds after the inflation shocks of the late 1970s and early 1980s. We believe that using an equity risk premium of 3.5 to 4 percent in the current environment better reflects the true long-term opportunity cost of equity capital and hence will yield more accurate valuations for companies.[24]

Q. WHAT EQUITY COST RATE IS INDICATED BY YOUR CAPM ANALYSIS?

A. The results of my CAPM study for the proxy group are provided below:

$$K = (R_f) + ß * [E(R_m) - (R_f)]$$

CAPM Equity Cost Rates

	Electric Proxy Group
Risk-Free Rate	**4.5%**
Beta	**0.82**

[24] Marc H. Goedhart, et al, "The Real Cost of Equity," *McKinsey on Finance* (Autumn 2002), p. 15.

Equity Risk Premium	**4.56%**
Equity Cost Rate	**8.2%**

V. EQUITY COST RATE SUMMARY

Q. PLEASE SUMMARIZE YOUR EQUITY COST RATE STUDY.

A. The results for my DCF and CAPM analyses for the proxy group of electric utility companies are indicated below:

	DCF	CAPM
Electric Proxy Group	**9.9%**	**8.2%**

Q. GIVEN THESE RESULTS, WHAT IS YOUR ESTIMATED EQUITY COST RATE FOR KU?

A. Given these results, I conclude that the appropriate equity cost rate for Electric Proxy Group in the 8.2%-9.9% range. However, since I give greater weight to the DCF model, and due to the current volatile market conditions which are discussed below, I am using the upper end of the range - 9.9% - for KU. In addition, due to the uncertain market conditions, I reserve the right to update my study prior to hearings. Finally, as previously discussed, given the common equity ratio proposed by the Company and adopted by the OAG, in comparison to the average common equity ratios for the Electric Proxy Group, this recommendation is very fair to the Company.

Q. FINALLY, PLEASE DISCUSS THE IMPACT OF RECENT CAPITAL MARKET VOLATILITY CONDITIONS ON THE EQUITY RISK

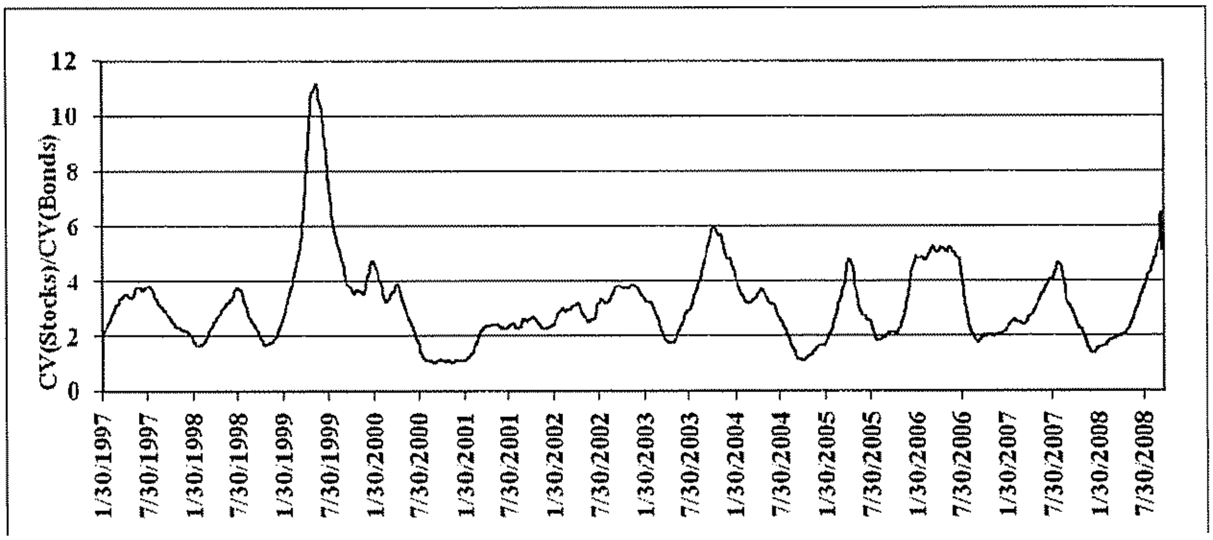
PREMIUM AND THE EQUITY COST RATE.

A. To assess the impact of recent capital market volatility on the equity risk premium and the equity cost rate, one must look at the volatility of stocks relative to bonds. I have performed such an analysis below. To compare the volatility of stock and bonds, one must standardize the volatility measure. This is normally done by dividing the volatility measure, the standard deviation, by the mean. This standardized volatility measure is known as the Coefficient of Variation ("CV").

Q. **GIVEN THESE OBSERVATIONS, PLEASE PROVIDE YOUR ASSESSMENT OF THE IMPACT OF RECENT CAPITAL MARKET CONDITIONS ON THE EQUITY COST RATE.**

A. I have performed an analysis of the volatility of stocks relative to bonds since 1997. I have used the S&P 500 and the Bear Sterns Bond Price Index ("BSBPI") and computed the CV using a 200-day mean and standard deviation. In Figure 1 below, I have graphed the ratio of the CV(Stock CV)/CV(Bond CV). Hence, this graph shows the standardized volatility of stocks relative to bonds. Higher levels of this ratio represent time periods when stock volatility is high relative to bond volatility, and low levels of this ratio occur during time periods when stock volatility is low relative to bonds. During the last two quarters of 2007, the volatility of bonds increased relative to stocks due to the subprime mortgage crisis. Through October of this year, stocks have increased in volatility relative to bonds. On the relative CV measure, stocks reached a five-year high in terms of relative volatility. As such, current market conditions suggest that stock volatility is high relative to bond volatility. In recognition of this situation, I am using the high end of the range for my equity cost rate recommendation for KU.

Coefficient of Variation
S&P 500 Price CV/Bear Sterns Bond Price Index CV
1997-2008



Q. ISN'T YOUR EQUITY COST RATE RECOMMENDATION LOW BY HISTORICAL STANDARDS?

A. Yes it is and appropriately so. My rate of return is low by historical standards for two reasons. First, as discussed above, current capital costs are very low by historical standards, with interest rates at a cyclical low not seen since the 1960s. And second, as previously discussed, the equity or market risk premium has declined.

Q. HOW DO YOU TEST THE REASONABLENESS OF YOUR COST OF EQUITY AND OVERALL RATE OF RETURN RECOMMENDATION?

A. To test the reasonableness of my equity cost rate recommendation, I examine the relationship between the return on common equity and the market-to-book ratios for the companies in the proxy group of electric utility companies.

Q. WHAT DO THE RETURNS ON COMMON EQUITY AND MARKET-TO-BOOK RATIOS FOR THE PROXY GROUP OF ELECTRIC UTILITY COMPANIES INDICATE ABOUT THE REASONABLENESS OF YOUR RECOMMENDATION?

A. Exhibit JRW-2 provides financial performance and market valuation statistics for the proxy group of electric utility companies. The mean current return on equity and market-to-book ratios for the group is summarized below:

	Current ROE	**Market-to-Book Ratio**
Electric Proxy Group	**10.2 %**	**1.63**

Source: Exhibit JRW-2

These results indicate that, on average, these companies are earning returns on equity above their equity cost rates. As such, this observation provides evidence that my recommended equity cost rate is reasonable and fully consistent with the financial performance and market valuation of the proxy group of electric utility companies.

VI. CRITIQUE OF KU'S RATE OF RETURN TESTIMONY

Q. PLEASE EVALUATE THE COMPANY'S RATE OF RETURN POSITION.

A. The Company's proposed rate of return is inflated due to overstated debt and equity cost rates. The debt cost rates were previously discussed. I will now discuss the errors with Dr. Avera's equity cost rate analysis.

Q. PLEASE REVIEW DR. AVERA'S EQUITY COST RATE APPROACHES.

A. Dr. Avera uses a proxy group of electric and gas companies as well as a proxy group of non-utility companies and employs DCF, CAPM, and Expected Earnings equity cost rate approaches.

Q. PLEASE SUMMARIZE DR. AVERA'S EQUITY COST RATE RESULTS.

A. Dr. Avera's equity cost rate estimates for KU are summarized in the table below. Based on these figures, he concludes that the appropriate equity cost rate for the Company is 11.25%.

Summary of Dr. Avera's Equity Cost Rate Approaches and Results

Approach	Utility Proxy Group	Non-Utility Proxy Group
DCF	10.9%	12.4%

Expected Earnings	**11.5%**	

Q. PLEASE DISCUSS YOUR ISSUES WITH DR. AVERA'S RECOMMENDED EQUITY COST RATE.

A. Dr. Avera's proposed return on common equity is too high primarily due to: (a) some of the companies in his utility proxy group, as well as his use of a non-utility proxy group; (b) an excessive adjustment to the dividend yield and an inflated growth rate in his DCF approach; (c) overstated equity risk premium estimates in his CAPM approach; and (d) a flawed Expected Earnings approach.

A. Proxy Groups

Q. PLEASE DISCUSS THE PROBLEM WITH DR. AVERA'S UTILITY PROXY GROUP.

A. Dr. Avera's utility proxy group includes a number of companies that are not appropriate because their operating revenues are from sources other than regulated electric utility services. These companies, and their percent of regulated electric revenues, include: Constellation Energy – 13%, Great Plains Energy – 39%, OGE Energy – 48%, Otter Tail Corp. – 28%, SEMPRA Energy – 27%, Westar Energy – 69%, and Wisconsin Energy – 62%.

Q. PLEASE DISCUSS THE PROBLEM WITH DR. AVERA'S NON-UTILITY PROXY GROUP.

A. Dr. Avera has estimated an equity cost rate for KU using a proxy group of 44 non-utility companies. These companies are listed in Exhibit WEA-3. This group includes such companies as Coca-Cola, General Electric, IBM, Johnson & Johnson, McDonald's, Microsoft, and NIKE. While these companies are large and successful, their lines of business are vastly different from the electric and gas utility businesses and they do not operate in highly regulated environment. As such, the non-utility group is not an appropriate proxy for the electric and gas utility operations of KU and therefore the equity cost rate results for this group should be ignored.

Q. PLEASE DISCUSS EXHIBIT JRW-8.

A. In Exhibit JRW-8, I have performed an analysis that highlights the significant financial differences between Dr. Avera's non-utility and utility proxy groups. I have shown four difference financial measures for the two groups: return on equity, market-to-book ratio, fixed asset turnover, and common equity ratio. The average return on equity for the non-utility group (23.53%) is twice the average return on common equity of the utility group (12.67%). As a result, the average market-to-book ratio of the non-utility group is also about double the average market-to-book ratio of the utility group return (3.53 vs. 1.63). The utility business is very capital intensive, and the fixed asset turnover ("FAT") ratio (revenues/net fixed assets) measures capital intensity with a lower figure indicating higher capital intensity. The FAT ratio for the utility group is only 0.90, while the ratio for the non-utility group is 5.44. Hence, in terms of capital intensity, the non-utility group is very dissimilar to the utility group. The common equity ("CE") ratio (common equity/total capital) measures the percent of capital represented by equity capital. For the utility group, the CE ratio is 53.88%, while the CE ratio for the non-utility group is 73.66%.

Overall, the results in Exhibit JRW-8 indicate that Dr. Avera's non-utility group has a significantly different financial profile than his utility group and therefore should not be used to estimate an equity cost rate for KU.

B. <u>DCF Approach</u>

Q. PLEASE SUMMARIZE DR. AVERA'S DCF ESTIMATES.

A. On pages 20-37 of his testimony and in Exhibits WEA-1 – WEA-4, Dr. Avera develops an equity cost rate by applying a DCF model to his utility and non-utility proxy groups. In the traditional DCF approach, the equity cost rate is the sum of the dividend yield and expected growth. For the DCF growth rate, Dr. Avera uses five measures of projected EPS growth – the projected EPS growth of Wall Street analysts as compiled by IBES, Reuters, Zack's, *Value Line* projected EPS growth, and the sum of internal ("br") and external ("sv") growth. Dr. Avera's DCF results are summarized below.

DCF Equity Cost Rate

	Utility Proxy Group	Non-Utility Proxy

		Group
Adjusted Dividend Yield	**3.7%**	**2.5%**
Expected EPS Growth from V-Line, IBES, Reuters, Zacks, and br+sv	**6.4% - 8.5%**	**9.19% - 10.79%**
DCF Result	**10.5% - 11.5%**	**12.4% - 12.9%**

Q. PLEASE EXPRESS YOUR CONCERNS WITH DR. AVERA'S DCF STUDY.

A. I have several issues with Dr. Avera's DCF equity cost rate. These are the utility and non-utility proxy groups, and the DCF growth rate measures. The errors in the proxy groups were discussed above. The DCF growth rate measures are reviewed below.

Q. PLEASE CRITIQUE DR. AVERA'S DCF GROWTH RATE MEASURES.

A. Dr. Avera employs five different DCF growth rate measures - the projected EPS growth of Wall Street analysts as compiled by IBES, Reuters, Zack's, *Value Line* projected EPS growth, and sustainable growth as measured by the sum of internal ("br") and external ("sv") growth.

Q. PLEASE INITIALLY DISCUSS DR. AVERA'S RELIANCE ON THE PROJECTED EPS GROWTH RATES OF WALL STREET ANALYSTS AND *VALUE LINE*.

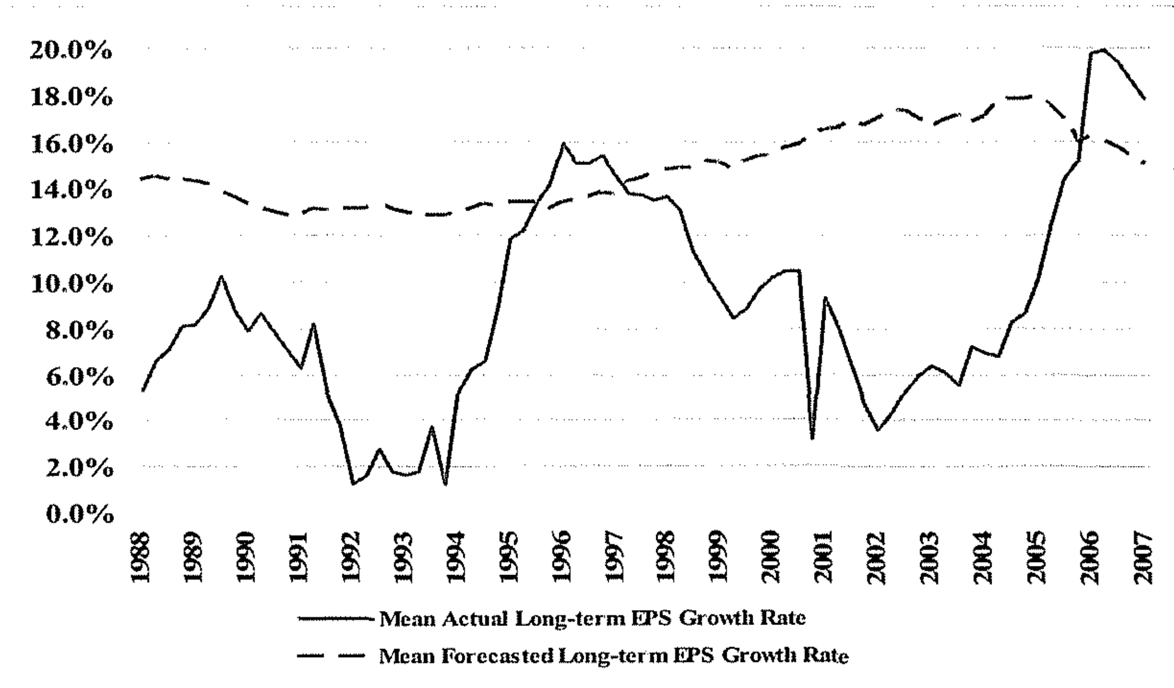
A. It seems highly unlikely that investors today would rely excessively on the forecasts of securities analysts and ignore historical growth in arriving at expected growth. It is well known in the academic world that the EPS forecasts of securities analysts are overly optimistic and biased upwards. In addition, as I show below, *Value Line*'s EPS forecasts are excessive and unrealistic.

Q. PLEASE REVIEW THE BIAS IN ANALYSTS' GROWTH RATE FORECASTS.

A. Analysts' growth rate forecasts are collected and published by Zacks, First Call, I/B/E/S, and Reuters. These services retrieve and compile EPS forecasts from Wall Street analysts. These analysts come from both the sell side (Merrill Lynch, Paine Webber) and the buy side (Prudential Insurance, Fidelity).

The problem with using these forecasts to estimate a DCF growth rate is that the objectivity of Wall Street research has been challenged, and many have argued that analysts' EPS forecasts are overly optimistic and biased upwards. To evaluate the accuracy of analysts' EPS forecasts, I have compared actual 3-5 year EPS growth rates with forecasted EPS growth rates on a quarterly basis over the past 20 years for all companies covered by the I/B/E/S data base. In the graph below, I show the average analysts' forecasted 3-5 year EPS growth rate with the average actual 3-5 year EPS growth rate. Because of the necessary 3-5 year follow-up period to measure actual growth, the analysis in this graph only: (1) covers forecasted and actual EPS growth rates through 1999 and (2) includes only companies that have 3-5 years of actual EPS data following the forecast period.

Long-Term Forecasted Versus Actual EPS Growth Rates
1988-2007



Source: Patrick J. Cusatis and J. Randall Woolridge, "The Accuracy of Analysts' Long-Term Earnings Per Share Growth Rate Forecasts," (July, 2008).

The following example shows how the results can be interpreted. For the 3-5-year period prior to the first quarter of 1999, analysts had projected an EPS growth rate of 15.13%, but companies only generated an average annual EPS growth rate over the 3-5 years of 9.37%. This projected EPS growth rate figure represented the average projected growth rate for over 1,510 companies, with an average of 4.88 analysts' forecasts per company. For the entire twenty-year period of the study, for each quarter there were on average 5.60 analysts' EPS projections for 1,281 companies. Overall, my findings indicate that forecast errors for long-term estimates are predominantly positive, which indicates an upward bias in growth rate estimates. The mean and median forecast errors over the observation period are 143.06% and

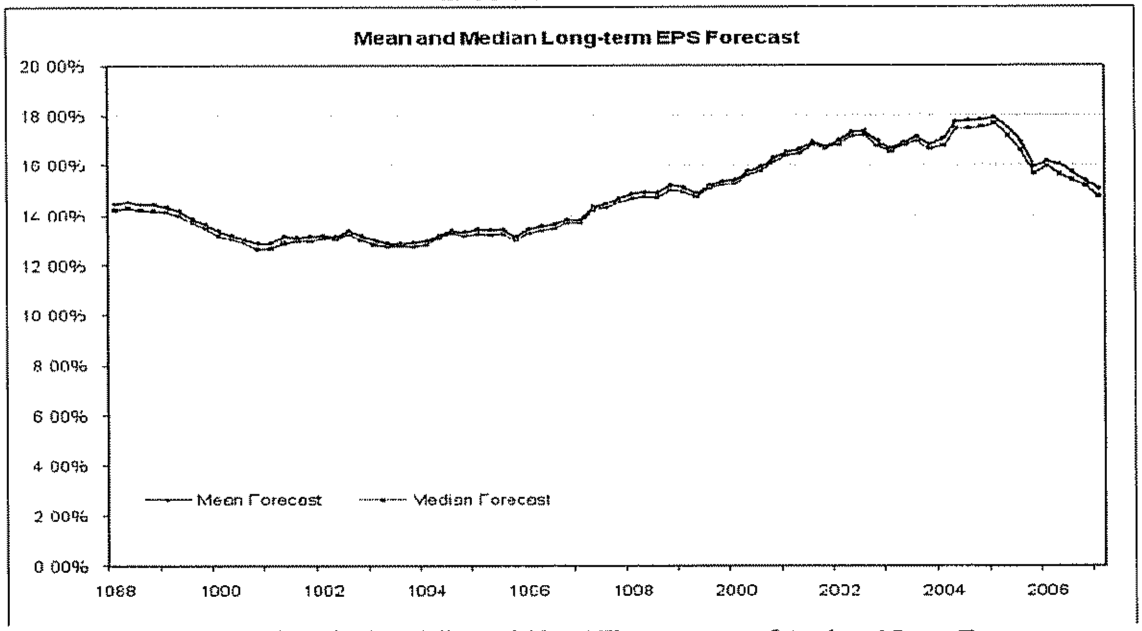
75.08%, respectively. The forecast errors are negative for only eleven of the eighty quarterly time periods: five consecutive quarters starting at the end of 1995 and six consecutive quarters starting in 2006. As shown in the figure below, the quarters with negative forecast errors were for the 3-5 year periods following earnings declines associated with the 1991 and 2001 economic recessions in the U.S. Overall. Thus, there is evidence of a persistent upward bias in long-term EPS growth forecasts.

The post-1999 period has seen the boom and then the bust in the stock market, an economic recession, 9/11, and the Iraq war. Furthermore, and highly significant in the context of this study, we have also had the New York State investigation of Wall Street firms and the subsequent Global Securities Settlement in which nine major brokerage firms paid a fine of $1.5B for their biased investment research.

To evaluate the impact of these events on analysts' forecasts, the graph below provides the average 3-5-year EPS growth rate projections for all companies provided in the I/B/E/S database on a quarterly basis from 1988 to 2006. In this graph no comparison to actual EPS growth rates is made, and hence, there is no follow-up period. Therefore, 3-5 year growth rate forecasts are shown until 2006, and since companies are not lost due to a lack of follow-up EPS data, these results are for a larger sample of firms. Analysts' forecasts for EPS growth were higher for this larger sample of firms, with a more pronounced run-up and then decline around the stock market peak in 2000. The average projected growth rate hovered in the 14.5%-17.5% range until

1995 and then increased dramatically over the next five years to 23.3% in the fourth quarter of the year 2000. Forecasted EPS growth has since declined to the 15.0% range.

Long-Term IBES Forecasted EPS Growth Rates
1988-2007



Source: Patrick J. Cusatis and J. Randall Woolridge, "The Accuracy of Analysts' Long-Term Earnings Per Share Growth Rate Forecasts," (July, 2008).

Q. WHAT IMPACT HAS RECENT STOCK MARKET AND REGULATORY DEVELOPMENTS HAD ON ANALYSTS' EPS GROWTH RATE FORECASTS?

A. Analysts' EPS growth rate forecasts have subsided somewhat since the stock market peak of 2000. In addition, the apparent conflict of interest within investment firms with investment banking and analysts' operations was addressed in the Global Analysts Research Settlements ("GARS"). GARS, as agreed upon on April 23, 2003 between the SEC, NASD, NYSE and ten of the largest U.S. investment firms, includes a number of regulations that were introduced to prevent investment bankers from pressuring analysts to provide favorable projections. Nonetheless, despite the new regulations, analysts' EPS growth rate forecasts have not significantly changed and continue to be overly-optimistic. Analysts' long-term EPS growth rate forecasts before and after the GARS, are about two times the level of historic GDP growth. Furthermore, as discussed later in my testimony, historic growth in GDP and corporate earnings has been in the 7% range.

Finally, these observations are supported by a *Wall Street Journal* article entitled "Analysts Still Coming Up Rosy – Over-Optimism on Growth Rates is Rampant – and the Estimates Help to Buoy the Market's Valuation." The following quote provides insight into the continuing bias in analysts' forecasts:

> Hope springs eternal, says Mark Donovan, who manages Boston Partners Large Cap Value Fund. "You would have thought that, given what happened in the last three years, people would have given up the ghost. But in large measure they have not."
>
> These overly optimistic growth estimates also show that, even with all the regulatory focus on too-bullish analysts allegedly influenced by their firms' investment-banking relationships, a lot of things haven't changed: Research remains rosy and many believe it always will.[25]

Q. IS THE BIAS IN ANALYSTS' GROWTH RATE FORECASTS GENERALLY KNOWN IN THE MARKETS?

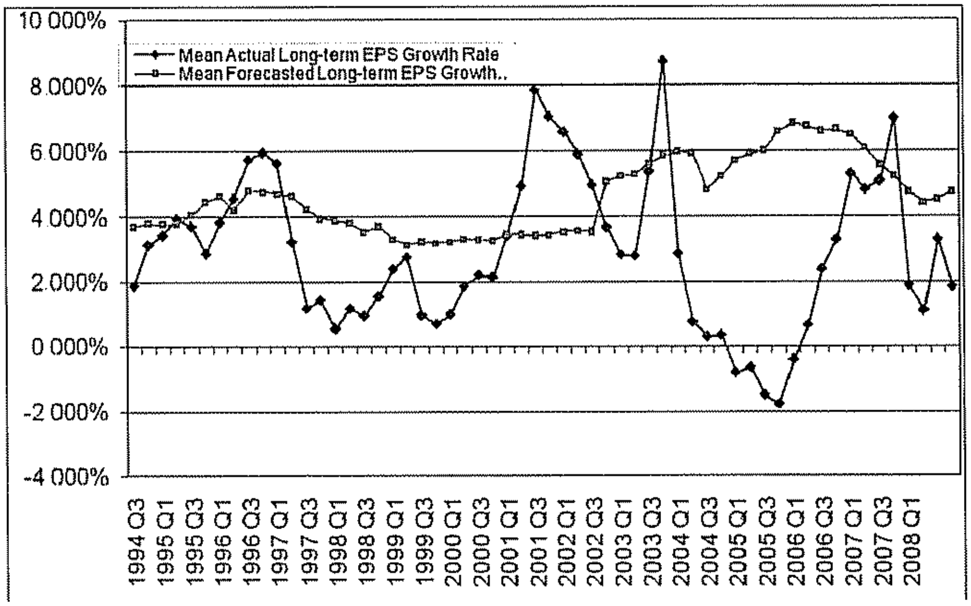
A. Yes. Exhibit JRW-9 provides a recent article published in the *Wall Street Journal* that discusses the upward bias in analysts' EPS growth rate forecasts.

[25] Ken Brown, "Analysts Still Coming Up Rosy – Over-Optimism on Growth Rates is Rampant – and the Estimates Help to Buoy the Market's Valuation." *Wall Street Journal*, (January 27, 2003), p. C1.

Q. ARE ANALYSTS' EPS GROWTH RATE FORECASTS LIKEWISE UPWARDLY BIASED FOR ELECTRIC UTILITY COMPANIES?

A. Yes. To evaluate whether analysts' EPS growth rate forecasts are upwardly biased for electric utility companies, I conducted a study similar to the one described above using a group of electric utility companies. The results are shown in the chart below. The projected EPS growth rates have declined from about six percent in the 1990s to about five percent in the 2000s. As shown, the achieved EPS growth rates have been volatile. Overall, the upward bias in EPS growth rate projections is not as pronounced for electric utility companies it is for all companies. Over the entire period, the average quarterly 3-5 year projected and actual EPS growth rates are 4.59% and 2.90%, respectively. These results are consistent with the results for companies in general -- analysts' projected EPS growth rate forecasts are upwardly-biased for utility companies.

Analysts' 3-5-Year Forecasted Versus Actual EPS Growth Rates
Electric Utility Companies
1990-2008



Q. ARE *VALUE LINE*'S GROWTH RATE FORECASTS SIMILARILY UPWARDLY BIASED?

A. Yes. *Value Line* has a decidedly positive bias to its earnings growth rate forecasts as well. To assess *Value Line's* earnings growth rate forecasts, I used the *Value Line Investment Analyzer*. The results are summarized in the table below. I initially filtered the database and found that *Value Line* has 3-5 year EPS growth rate forecasts for 2,453 firms. The average projected EPS growth rate was 14.6%. This is high given that the average historical EPS growth rate in the U.S. is about 7%. A major factor seems to be that *Value Line* only predicts negative EPS growth for 47 companies. This is less than two percent of the companies covered by *Value Line*. Given the ups and downs of corporate earnings, this is unreasonable.

Value Line 3-5 year EPS Growth Rate Forecasts

	Average Projected EPS Growth rate	Number of Negative EPS Growth Projections	Percent of Negative EPS Growth Projections
2,453 Companies	**14.6%**	**47**	**1.9%**

To put this figure in perspective, I screened the *Value Line* companies to see what percent of companies covered by *Value Line* had experienced negative EPS growth rates over the past five years. *Value Line* reported a five-year historic growth rate for 2,371 companies. The results shown in the table below indicate that the average 5-year historic growth rate was 12.9%, and *Value Line* reported negative historic growth for 476 firms which represents 20.1% of these companies. It should be noted that the past five years have been a period of rapidly rising corporate earnings growth as the economy and businesses have rebounded from the recession of 2001.

Historical Five-Year EPS Growth Rates for *Value Line* Companies

	Average Historical EPS Growth rate	Number with Negative Historical EPS Growth	Percent with Negative Historical EPS Growth
2,371 Companies	**12.9%**	**476**	**20.1%**

These results indicate that *Value Line*'s EPS forecasts are excessive and unrealistic. It appears that the analysts at *Value Line* are similar to their Wall Street brethren in that they are reluctant to forecasts negative earnings growth.

Q. PLEASE SUMMARIZE YOUR ASSESSMENT OF DR. AVERA'S DCF GROWTH RATE.

A. Dr. Avera's DCF equity cost rate is overstated because he has relied so heavily on the upwardly biased EPS growth rate forecasts of Wall Street analysts and *Value Line*.

C. <u>CAPM Analysis</u>

Q. PLEASE DISCUSS DR. AVERA'S CAPM.

A. On pages 37 to 39 and Exhibits WEA-5 and WEA-6, Dr. Avera applies the CAPM method to his utility and non-utility proxy groups. The results are summarized below:

CAPM Equity Cost Rate

	Utility Proxy Group	Non-Utility Proxy Group
Risk-Free Rate	**4.40%**	**4.40%**
Beta	**0.84**	**0.79**
Market Risk Premium	**8.90%**	**8.90%**
CAPM Result	**11.9%**	**11.4%**

Q. WHAT ARE THE ERRORS IN DR. AVERA'S CAPM ANALYSIS?

A. The major flaw in Dr. Avera's CAPM analysis is his equity or market risk premium of 8.90%.

Q. PLEASE REVIEW DR. AVERA'S EQUITY OR MARKET RISK PREMIUM IN HIS CAPM APPROACH.

A. The primary problem with Dr. Avera's CAPM analysis is the size of the market or equity risk premium. Dr. Avera develops an expected market risk premium of 8.90% by: (1) applying the DCF model to the S&P 500 to get an expected market return; and (2) subtracting the risk-free rate of interest. Dr. Avera estimated market return of 13.3% for the S&P 500 equals the sum of the dividend yield of 2.4% and expected EPS growth rate of 10.9%. The expected EPS growth rate is the average of the expected EPS growth rates from IBES and *Value Line*. The primary error in this approach is that his expected DCF growth rate. As previously discussed, the expected EPS growth rates of Wall Street analysts and *Value Line* are upwardly biased. Therefore, as explained below, this produces an overstated expected market return and equity risk premium.

Q. BEYOND YOUR PREVIOUS DISCUSSION OF THE UPWARD BIAS IN ANALYSTS' AND *VALUE LINE*'S EPS GROWTH RATE FORECASTS, WHAT OTHER EVIDENCE CAN YOU PROVIDE THAT DR. AVERA'S S&P 500 GROWTH RATE IS EXCESSIVE?

A. A long-term EPS growth rate of 10.9% is inconsistent with economic and earnings growth in the U.S. The long-term economic and earnings growth rate in the U.S. has only been about 7%. I have performed a study of the growth in nominal GDP, S&P 500 stock price appreciation, and S&P 500 EPS and DPS growth since 1960. The results are provided on page 1 of Exhibit JRW-10, and a summary is given in the table below.

GNP, S&P 500 Stock Price, EPS, and DPS Growth
1960-Present

Nominal GDP	7.20%
S&P 500 Stock Price Appreciation	7.12%
S&P 500 EPS	7.36%
S&P 500 DPS	5.77%
Average	6.86%

These results offer compelling evidence that a long-run growth rate of about 7% is appropriate for companies in the U.S. By comparison, Dr. Avera's long-run growth rate projection of 10.9% is clearly not realistic. These estimates suggest that companies in the U.S. would be expected to: (1) increase their growth rate of EPS by over 50% in the future and (2) maintain that growth indefinitely in an economy that is expected to grow at about one half his projected growth rates. Such a scenario is not economically feasible or reasonable.

Q. PLEASE PROVIDE A SUMMARY ASSESSMENT OF DR. AVERA'S EQUITY RISK PREMIUM OF 8.9% DERIVED USING AN EXPECTED MARKET RETURN OF 13.3%.

A. Dr. Avera's equity risk premium derived from an expected market return of 13.3% is inflated and does not reflect current market fundamentals or prospective economic and earnings growth. As previously discussed, at the present time stock prices (relative to earnings and dividends) are high while interest rates are low. Major stock market upswings that produce above average returns tend to occur when stock prices are low and interest rates are high. Thus, *current market conditions do not suggest above-average expected* market return. Consistent with this observation, the financial forecasters in the Federal Reserve Bank of Philadelphia survey expect a market return of 6.80% over the next ten years. In addition, the third quarter 2008 *CFO Magazine* – Duke University Survey of over 500 CFOs shows an expected return on the S&P 500 of 7.79% over the next ten years.

Q. TO CONCLUDE THIS DISCUSSION, PLEASE SUMMARIZE DR. AVERA'S MARKET RISK PREMIUM AND CAPM RESULTS IN LIGHT OF THE EVIDENCE ON RISK PREMIUMS IN TODAY'S MARKETS.

A. Dr. Avera's market risk premium of 8.9% is well in excess of the equity risk premium estimates discovered in recent academic studies by leading finance scholars and is especially out of touch with the real world of finance. Investment banks, consulting firms, and CFOs use the equity risk premium concept every day in making financing, investment, and valuation decisions. The results of studies and surveys from the real world of finance indicate an equity risk premium in the 4 percent range and not in the 8 percent range.

D. <u>Expected Earnings Approach</u>

Q. PLEASE DISCUSS DR. AVERA'S EXPECTED EARNINGS ANALYSIS.

A. In pages 39-41 of his testimony and Exhibit WEA-7, Dr. Avera estimates an equity cost rate of 11.8% for the Company employing an approach he calls the Expected Earnings ("EE") approach. His methodology simply involves using the expected ROE for the companies in his proxy group as estimated by *Value Line*. This approach is fundamentally flawed for several reasons. First, these results include the profits associated with the unregulated operations of the utility proxy group. As previously noted, the unregulated operations are significant for several of the utility proxy companies. More importantly, since Dr. Avera has not evaluated the market-to-book ratios for these companies, he cannot indicate whether the past and projected returns on common equity are above or below investors' requirements. These returns on common equity are excessive if the market-to-book ratios for these companies are above 1.0. For example, Constellation Energy's projected return on equity is 16.9%. However, I doubt if any financial analyst, including Dr. Avera, would suggest that Constellation has an equity cost rate of 16.9%. Indeed, the market-to-book ratio for Constellation is about 2.0X. This indicates that its return on equity is above its cost of equity capital.

E. Flotation Costs

Q. PLEASE DISCUSS DR. AVERA'S ADJUSTMENT FOR FLOTATION COSTS.

A. While making no specific adjustment, Dr. Avera has recommended that flotation costs be considered in setting a return on equity for the Company. This consideration is erroneous for several reasons. First, the Company has not identified any actual flotation costs. Therefore, the Company is requesting annual revenues in the form of a higher return on equity for flotation costs that have not been identified. Second, it is commonly argued that a flotation cost adjustment (such as that used by the Company) is necessary to prevent the dilution of the existing shareholders. In this case, a floatation cost adjustment is justified by reference to bonds and the manner in which issuance costs are recovered by including the amortization of bond flotation costs in annual financing costs. However, this is incorrect for several reasons:

(1) If an equity flotation cost adjustment is similar to a debt flotation cost adjustment, the fact that the market-to-book ratios for utility companies are over 1.5X actually suggests that there should be a flotation cost reduction (and not increase) to the equity cost rate. This is because when (a) a bond is issued at a price in excess of face or book value, and (b) the difference between market price and the book value is greater than the flotation or issuance costs, the cost of that debt is lower than the coupon rate of the debt. The amount by which market values of utility companies are in excess of book values is much greater than flotation costs. Hence, if common stock flotation costs were exactly like bond flotation costs, and one was making an explicit flotation cost adjustment to the cost of common equity, the adjustment would be downward;

(2) If a flotation cost adjustment is needed to prevent dilution of existing stockholders' investment, then the reduction of the book value of stockholder investment associated with flotation costs can occur only when a company's stock is selling at a market price at/or below its book value. As noted above, utility companies are selling at market prices well in excess of book value. Hence, when new shares are sold, existing shareholders realize an **increase** in the book value per share of their investment, not a decrease;

(3) Flotation costs consist primarily of the underwriting spread or fee and not out-of-pocket expenses. On a per share basis, the underwriting spread is the

difference between the price the investment banker receives from investors and the price the investment banker pays to the company. Hence, these are not expenses that must be recovered through the regulatory process. Furthermore, the underwriting spread is known to the investors who are buying the new issue of stock, who are well aware of the difference between the price they are paying to buy the stock and the price that the Company is receiving. The offering price which they pay is what matters when investors decide to buy a stock based on its expected return and risk prospects. Therefore, the company is not entitled to an adjustment to the allowed return to account for those costs; and

(4) Flotation costs, in the form of the underwriting spread, are a form of a transaction cost in the market. They represent the difference between the price paid by investors and the amount received by the issuing company. Whereas the Company believes that it should be compensated for these transactions costs, they have not accounted for other market transaction costs in determining a cost of equity for the Company. Most notably, brokerage fees that investors pay when they buy shares in the open market are another market transaction cost. Brokerage fees increase the effective stock price paid by investors to buy shares. If the Company had included these brokerage fees or transaction costs in their DCF analysis, the higher effective stock prices paid for stocks would lead to lower dividend yields and equity cost rates. This would result in a downward adjustment to their DCF equity cost rate.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

Appendix A
Educational Background, Research, and Related Business Experience
J. Randall Woolridge

J. Randall Woolridge is a Professor of Finance and the Goldman, Sachs & Co. and Frank P. Smeal Endowed Faculty Fellow in Business Administration in the College of Business Administration of the Pennsylvania State University in University Park, PA In addition, Professor Woolridge is Director of the Smeal College Trading Room and President and CEO of the Nittany Lion Fund, LLC.

Professor Woolridge received a Bachelor of Arts degree in Economics from the University of North Carolina, a Master of Business Administration degree from the Pennsylvania State University, and a Doctor of Philosophy degree in Business Administration (major area-finance, minor area-statistics) from the University of Iowa. At Iowa he received a Graduate Fellowship and was awarded membership in Beta Gamma Sigma, a national business honorary society. He has taught Finance courses at the University of Iowa, Cornell College, and the University of Pittsburgh, as well as the Pennsylvania State University. These courses include corporation finance, commercial and investment banking, and investments at the undergraduate, graduate, and executive MBA levels.

Professor Woolridge's research has centered on the theoretical and empirical foundations of corporation finance and financial markets and institutions. He has published over 35 articles in the best academic and professional journals in the field, including the *Journal of Finance,* the *Journal of Financial Economics,* and the *Harvard Business Review*. His research has been cited extensively in the business press. His work has been featured in the *New York Times*, *Forbes*, *Fortune*, *The Economist*, *Financial World*, *Barron's*, *Wall Street Journal*, *Business Week*, *Washington Post*, *Investors' Business Daily*, *Worth Magazine*, *USA Today*, and other publications. In addition, Dr. Woolridge has appeared as a guest to discuss the implications of his research on CNN's *Money Line*, CNBC's *Morning Call* and *Business Today*, and Bloomberg Televisions' *Morning Call*.

Professor Woolridge's popular stock valuation book, *The StreetSmart Guide to Valuing a Stock* (McGraw-Hill, 2003), was released in its second edition. He has also co-authored *Spinoffs and Equity Carve-Outs: Achieving Faster Growth and Better Performance* (Financial Executives Research Foundation, 1999) as well as a new textbook entitled *Applied Principles of Finance* (Kendall Hunt, 2006). Dr. Woolridge is a founder and a managing director of www.valuepro.net - a stock valuation website.

Professor Woolridge has also consulted with and prepared research reports for major corporations, financial institutions, and investment banking firms, and government agencies. In addition, he has directed and participated in over 500 university- and company- sponsored professional development programs for executives in 25 countries in North and South America, Europe, Asia, and Africa.

Dr. Woolridge has prepared testimony and/or provided consultation services in the following cases:

Pennsylvania: Dr. Woolridge has prepared testimony on behalf of the Pennsylvania Office of Consumer Advocate in the following cases before the Pennsylvania Public Utility Commission; Bell Telephone Company (R-811819), Peoples Natural Gas Company (R-832315), Pennsylvania Power Company (R-832409), Western Pennsylvania Water Company (R-832381), Pennsylvania Power Company (R-842740), Pennsylvania Gas and Water Company (R-850178), Metropolitan Edison Company (R-860384), Pennsylvania Electric Company (R-860413), North Penn Gas Company (R-860535), Philadelphia Electric Company (R-870629), Western Pennsylvania Water Company (R-870825), York Water Company (R-870749), Pennsylvania-American Water Company (R-880916), Equitable Gas Company (R-880971), the Bloomsburg Water Co. (R-891494), Columbia Gas of Pennsylvania, Inc. (R-891468), Pennsylvania-American Water Company (R-90562), Breezewood Telephone Company (R-901666), York Water Company (R-901813), Columbia Gas of Pennsylvania, Inc. (R-901873), National Fuel Gas Corporation (R-911912), Pennsylvania-American Water Company (R-911909), Borough of Media Water Fund (R-912150), UGI Utilities, Inc. - Electric Utility Division (R-922195), Dauphin Consolidated Water Supply Company - General Waterworks of Pennsylvania, Inc, (R-932604), National Fuel Gas Corporation (R-932548), Commonwealth Telephone Company (I-

920020), Conestoga Telephone and Telegraph Company (I-920015), Peoples Natural Gas Company (R-932866), Blue Mountain Consolidated Water Company (R-932873), National Fuel Gas Corporation (R-942991), UGI - Gas Division (R-953297), UGI - Electric Division (R-953534), Pennsylvania-American Water Company (R-973944), Pennsylvania-American Water Company (R-994638), Philadelphia Suburban Water Company (R-994868;R-994877;R-994878; R-9948790), Philadelphia Suburban Water Company (R-994868), Wellsboro Electric Company (R-00016356), Philadelphia Suburban Water Company (R-00016750), National Fuel Gas Corporation (R-00038168), Pennsylvania-American Water Company (R-00038304), York Water Company (R-00049165), Valley Energy Company (R-00049345), Wellsboro Electric Company (R-00049313), National Fuel Gas Corporation (R-00049656), T.W. Phillips Gas and Oil Co. (R-00051178), PG Energy (R-00061365), City of Dubois Water Company (Docket No. R-00050671), R-00049165), York Water Company (R-00061322), Emporium Water Company (R-00061297), Pennsylvania-American Water Company (R-00072229),

New Jersey: Dr. Woolridge prepared testimony for the New Jersey Department of the Public Advocate, Division of Rate Counsel: New Jersey-American Water Company (R-91081399J), New Jersey-American Water Company (R-92090908J), and Environmental Disposal Corp. (R-94070319).

Alaska: Dr. Woolridge prepared testimony for Attorney General's Office of Alaska: Golden Heart Utilities, Inc. and College Utilities Corp. (Water Public Utility Service TA-29-118 and Sewer Public Utility Service TA-82-97), Anchorage Water and Wastewater Utility (TA-106-122).

Arizona: Dr. Woolridge prepared testimony for Utility Division staff of the Arizona Corporation Commission, Arizona Public Service Company (Docket No. E-01345A-06-0009).

Hawaii: Dr. Woolridge prepared testimony for the Hawaii Office of the Consumer Advocate: East Honolulu Community Services, Inc. (Docket No. 7718).

Delaware: Dr. Woolridge prepared testimony for the Delaware Division of Public Advocate: Artesian Water Company (R-00-649). Dr. Woolridge prepared testimony for the staff of the Public Service Commission: Artesian Water Company (R-06-158).

Ohio: Dr. Woolridge prepared testimony for the Ohio Office of Consumers' Council: SBC Ohio (Case No. 02-1280-TP-UNC R-00-649), and Cincinnati Gas & Electric Company (Case No. 05-0059-EL-AIR).

Texas: Dr. Woolridge prepared testimony for the Atmos Cities Steering Committee: Mid-Texas Division of Atmos Energy Corp. (Docket No. 9670).

New York: Dr. Woolridge prepared testimony for the County of Nassau in New York State: Long Island Lighting Company (PSC Case No. 942354).

Florida: Dr. Woolridge prepared testimony for the Office of Public Counsel in Florida: Florida Power & Light Co. (Docket No. 050045-EL).

Indiana: Dr. Woolridge prepared testimony for the Indiana Office of Utility Consumer Counsel (OUCC) in the following cases: Southern Indiana Gas and Electric Company (IURC Cause No. 43111 and IURC Cause No. 43112).

Oklahoma: Dr. Woolridge prepared testimony for the Oklahoma Industrial Energy Companies (OIEC) in the following cases: Public Service Company of Oklahoma (Cause No PUD 200600285), Oklahoma Gas & Electric Company (Cause No. PUD 200700012

Appendix A
Educational Background, Research, and Related Business Experience
J. Randall Woolridge

Connecticut: Dr. Woolridge prepared testimony for the Office of Consumer Counsel in Connecticut: United Illuminating (Docket No. 96-03-29), Yankee Gas Company (Docket No. 04-06-01), Southern Connecticut Gas Company (Docket No. 03-03-17), the United Illuminating Company (Docket No. 05-06-04), Connecticut Light and Power Company (Docket No. 05-07-18), Birmingham Utilities, Inc. (Docket No. 06-05-10), Connecticut Water Company (Docket No. 06-07-08), Connecticut Natural Gas Corp. (Docket No. 06-03-04), Aquarion Water Company (Docket No. 07-05-09), Yankee Gas Company (Docket No. 06-12-02), and Connecticut Light and Power Company (Docket No. 07-07-01).

California: Dr. Woolridge prepared testimony for the Office of Ratepayer Advocate in California: San Gabriel Valley Water Company (Docket No. 05-08-021), Pacific Gas & Electric (Docket No. 07-05-008), San Diego Gas & Electric (Docket No. 07-05-007), and Southern California Edison (Docket No. 07-05-003).

South Carolina: Dr. Woolridge prepared testimony for the Office of Regulatory Staff in South Carolina: South Carolina Electric and Gas Company (Docket No. 2005-113-G), Carolina Water Service Co. (Docket No. 2006-87-WS), Tega Cay Water Company (Docket No. 2006-97-WS), United Utilities Companies, Inc. (Docket No. 2006-107-WS).

Missouri: Dr. Woolridge prepared testimony for the Department of Energy in Missouri: Kansas City Power & Light Company (CASE NO. ER-2006-0314). Dr. Woolridge prepared testimony for the Office of Attorney General of Missouri: Union Electric Company (CASE NO. ER-2007-0002).

Kentucky: Dr. Woolridge prepared testimony for the Office of Attorney General in Kentucky: Kentucky-American Water Company (Case No. 2004-00103), Union Heat, Light, and Power Company (Case No. 2004-00042), Kentucky Power Company (Case No. 2005-00341), Union Heat, Light, and Power Company (Case No. 2006-00172), Atmos Energy Corp. (Case No. 2006-00464), Columbia Gas Company (Case No. 2007-00008), Delta Natural Gas Company (Case No. 2007-00089), Kentucky-American Water Company (Case No. 2007-00143).

Washington, D.C.: Dr. Woolridge prepared testimony for the Office of the People's Counsel in the District of Columbia: Potomac Electric Power Company (Formal Case No. 939).

Washington: Dr. Woolridge consulted with trial staff of the Washington Utilities and Transportation Commission on the following cases: Puget Energy Corp. (Docket Nos. UE-011570 and UG-011571); and Avista Corporation (Docket No. UE-011514).

Kansas: Dr. Woolridge prepared testimony on behalf of the Kansas Citizens' Utility Ratepayer Board in the following cases: Western Resources Inc. (Docket No. 01-WSRE-949-GIE), UtiliCorp (Docket No. 02-UTCG701-CIG), and Westar Energy, Inc. (Docket No. 05-WSEE-981-RTS).

FERC: Dr. Woolridge has prepared testimony on behalf of the Pennsylvania Office of Consumer Advocate in the following cases before the Federal Energy Regulatory Commission: National Fuel Gas Supply Corporation (RP-92-73-000) and Columbia Gulf Transmission Company (RP97-52-000).
Vermont: Dr. Woolridge prepared testimony for the Department of Public Service in the Central Vermont Public Service (Docket No. 6988) and Vermont Gas Systems, Inc. (Docket No. 7160).

Exhibit JRW-1

Kentucky Utilities Company
Cost of Capital

Electric Utility Operations
Capitalization at April 30, 2008

Capital Source	Capitalization Amount*	Capitalization Ratio*	Cost Rate	Weighted Cost Rate
Short-Term Debt	55,598	2.70%	2.63%	0.07%
Long-Term Debt	916,790	44.67%	5.21%	2.33%
Common Equity	1,080,552	52.63%	9.90%	5.21%
Total	2,052,940	100.00%		7.61%

* Capitalization ratios developed on page 1 of Exhibit JRW-3

Exhibit JRW-2
Kentucky Utilities Company
Summary Financial Statistics

Electric Proxy Group

Company	Operating Revenue ($mil)	Percent Elec Revenue	Net Plant ($mil)	Moody's Bond Rating	Long-Term Interest Coverage	Primary Service Area	Common Equity Ratio*	Return on Equity	Market to Book Ratio
ALLETE, Inc. (NYSE-ALE)	849.8	87	1,153.1	NR	6.0	MN, WS	60	13.2	163
Ameren Corporation (NYSE-AEE)	7,671.0	82	15,566.0	Baa2	4.2	IL, MO	46	10.4	129
American Electric Power Co. (NYSE-AEP)	14,078.0	90	31,004.0	Baa1	3.0	11 States	39	14.9	145
Central Vermont Public Serv. Corp. (NYSE-C	340.7	100	327.6	NR	4.1	VT	50	8.8	133
Cleco Corporation (NYSE-CNL)	1,042.7	95	1,877.6	Baa1	2.5	LA	49	12.5	149
DPL Inc.(NYSE-DPL)	1,552.1	100	2,793.0	A2	6.2	OH	36	NM	308
Edison International (NYSE-EIX)	13,283.0	80	17,698.0	A2	2.1	CA	43	12.7	173
Empire District Electric Co. (NYSE-EDE)	501.2	87	1,222.3	Baa1	2.2	MO,KS,OK,AR	45	7.0	126
FirstEnergy Corporation (NYSE-FE)	13,242.0	88	16,703.0	Baa2	4.6	OH,PA,NJ	40	13.7	237
FPL Group, Inc. (NYSE-FPL)	15,278.0	76	30,499.0	Aa3	3.2	FL	42	12.1	230
Hawaiian Electric Industries, Inc. (NYSE-HE)	2,712.0	81	2,460.5	Baa2	2.9	HI	29	9.3	165
IDACORP, Inc. (NYSE-IDA)	902.6	100	2,687.8	A3	2.4	ID,OR	46	6.6	114
Northeast Utilities (NYSE-NU)	5,637.9	84	7,452.6	Baa1	2.8	CT,NH,MA	42	7.9	144
NSTAR (NYSE-NST)	3,173.0	78	4,176.9	A1	3.3	MA	40	7.4	207
Pinnacle West Capital Corp. (NYSE-PNW)	3,628.0	86	8,570.9	Baa2	3.0	AZ	52	8.8	94
PNM Resources, Inc. (NYSE-PNM)	1,625.0	100	2,972.7	Baa3	0.0	NM	40	NM	57
Progress Energy Inc. (NYSE-PGN)	8,885.0	100	16,986.0	A2	2.9	NC,SC,FL	46	7.3	134
Southern Company (NYSE-SO)	16,070.1	99	34,562.6	A2	4.1	GA,AL,FL,MS	41	13.7	227
UIL Holdings Corporation (NYSE-UIL)	941.5	100	969.6	Baa2	4.2	CT	44	10.5	186
UniSource Energy Corporation (NYSE-UNS)	1,424.2	85	2,505.8	Baa2	1.7	AZ	26	6.5	169
Xcel Energy Inc. (NYSE-XEL)	10,298.9	78	16,955.1	A3	2.9	CO,MN,WS,ND,SD,MI	43	9.9	141
Mean	5,863.7	89	10,435.4	Baa1	3.3		43	10.2	163

Data Source: AUS *Utility Reports*, September, 2008; Service Area and Long-Term Interest Coverage are from *Value Line Investment Survey*, 2008.

Exhibit JRW-3
Kentucky Utilities Company
Capital Structure Ratios

Panel A - KU Recommended Capitalization Ratios

Capital	Capitalization Ratios
Short-Term Debt	2.70%
Long-Term Debt	44.67%
Common Equity	52.63%
Total Capital	100.00%

Source: Testimony of Mr. S. Bradford Rives

Panel B - KU - OAG Capitalization Ratios
Electric Utility Operations

Short-Term Debt	55,598	2.70%
Long-Term Debt	916,790	44.67%
Common Equity	1,080,552	52.63%
Total	2,052,940	100.00%

Exhibit JRW-3
Kentucky Utilities Company
Capital Structure Ratios

Company	Jan	Feb	Mar	Apr	May	June	July	Aug	Sep	Oct	Mean
ALLETE, Inc. (NYSE-ALE)	62.0	62.0	63.0	63.0	63.0	60.0	60.0	60.0	60.0	57.0	61.0
Ameren Corporation (NYSE-AEE)	49.0	49.0	49.0	47.0	47.0	47.0	47.0	47.0	46.0	46.0	47.4
American Electric Power Co. (NYSE-AEP)	39.0	39.0	39.0	39.0	39.0	39.0	39.0	39.0	39.0	39.0	39.0
Central Vermont Public Serv. Corp. (NYSE-CV)	59.0	59.0	59.0	60.0	60.0	51.0	51.0	51.0	50.0	50.0	55.0
Cleco Corporation (NYSE-CNL)	56.0	56.0	56.0	54.0	54.0	51.0	51.0	51.0	49.0	49.0	52.7
DPL Inc.(NYSE-DPL)	34.0	34.0	34.0	35.0	35.0	35.0	36.0	36.0	36.0	39.0	35.4
Edison International (NYSE-EIX)	44.0	44.0	44.0	44.0	44.0	43.0	43.0	43.0	43.0	42.0	43.4
Empire District Electric Co. (NYSE-EDE)	45.0	45.0	45.0	48.0	48.0	45.0	45.0	45.0	45.0	44.0	45.5
FirstEnergy Corporation (NYSE-FE)	43.0	43.0	43.0	42.0	42.0	41.0	41.0	41.0	40.0	40.0	41.6
FPL Group, Inc. (NYSE-FPL)	43.0	43.0	43.0	44.0	44.0	43.0	43.0	43.0	42.0	42.0	43.0
Hawaiian Electric Industries, Inc. (NYSE-HE)	27.0	27.0	27.0	27.0	27.0	29.0	29.0	29.0	29.0	38.0	28.9
IDACORP, Inc. (NYSE-IDA)	48.0	48.0	48.0	47.0	47.0	46.0	46.0	46.0	46.0	46.0	46.8
Northeast Utilities (NYSE-NU)	43.0	43.0	43.0	43.0	43.0	42.0	42.0	42.0	42.0	40.0	42.3
NSTAR (NYSE-NST)	41.0	41.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.2
Pinnacle West Capital Corp. (NYSE-PNW)	50.0	50.0	50.0	49.0	49.0	49.0	49.0	49.0	52.0	52.0	49.9
PNM Resources, Inc. (NYSE-PNM)	47.0	47.0	47.0	47.0	47.0	47.0	40.0	40.0	40.0	41.0	44.3
Progress Energy Inc. (NYSE-PGN)	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	43.0	45.7
Southern Company (NYSE-SO)	42.0	42.0	42.0	41.0	41.0	41.0	41.0	41.0	41.0	41.0	41.3
UIL Holdings Corporation (NYSE-UIL)	44.0	44.0	44.0	44.0	44.0	44.0	44.0	44.0	44.0	44.0	44.0
UniSource Energy Corporation (NYSE-UNS)	28.0	28.0	28.0	29.0	29.0	27.0	27.0	27.0	26.0	26.0	27.5
Xcel Energy Inc. (NYSE-XEL)	43.0	43.0	43.0	44.0	44.0	43.0	43.0	43.0	43.0	42.0	43.1
Mean	44.4	44.4	44.4	44.4	44.4	43.3	43.0	43.0	42.8	42.9	43.7

Data Source: AUS *Utility Reports*

Exhibit JRW-4

Long-Term 'A' Rated Public Utility Bonds

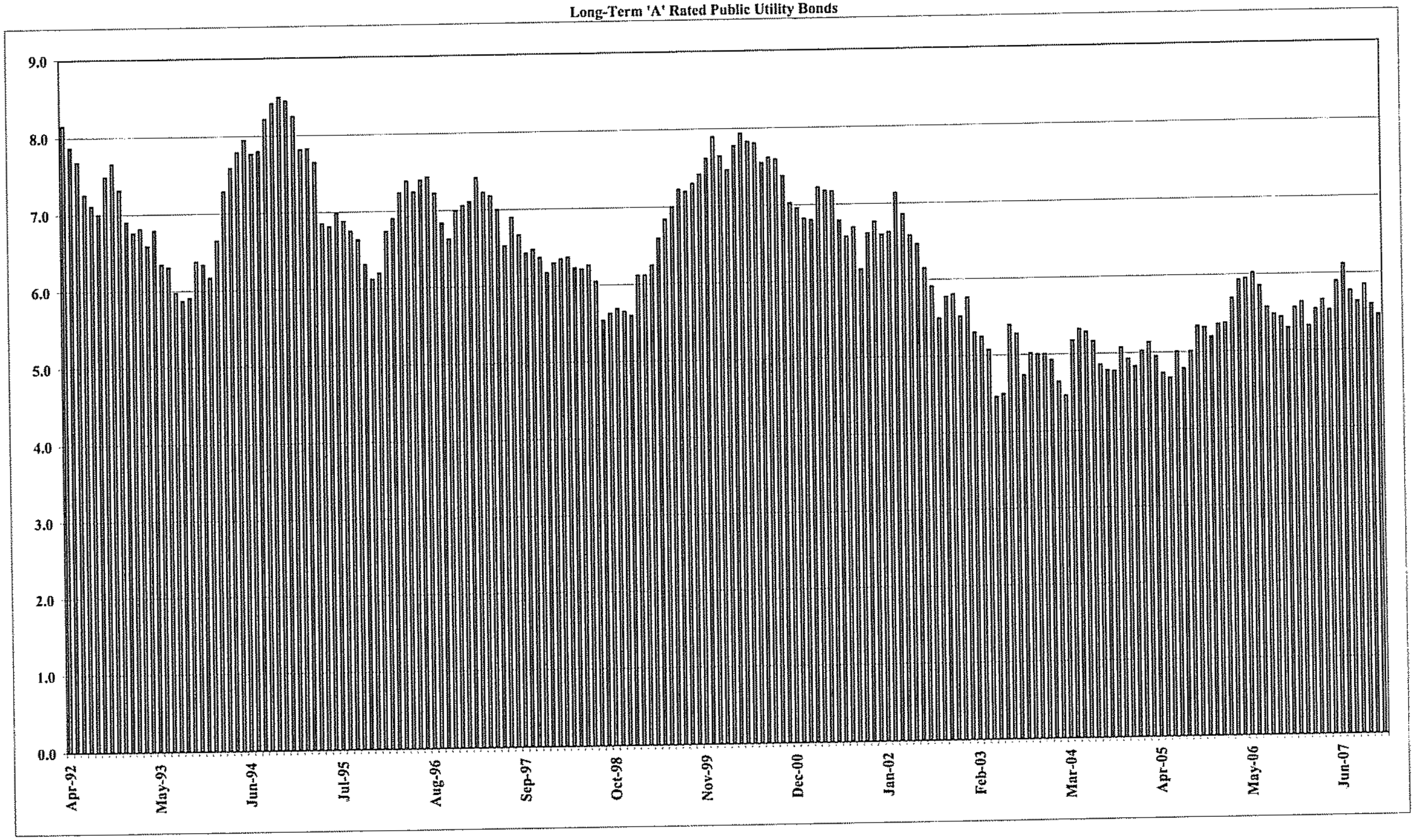
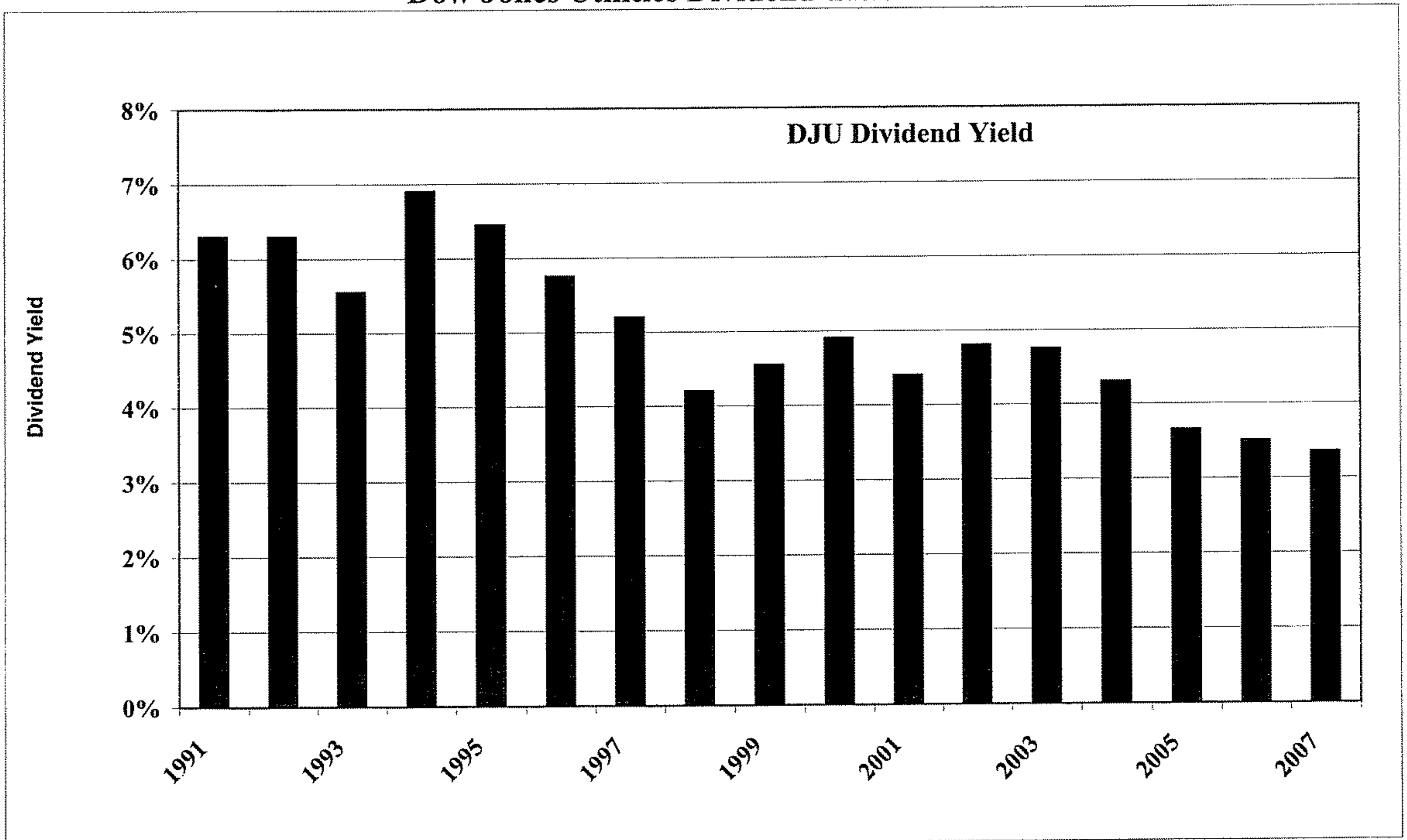


Exhibit JRW-4

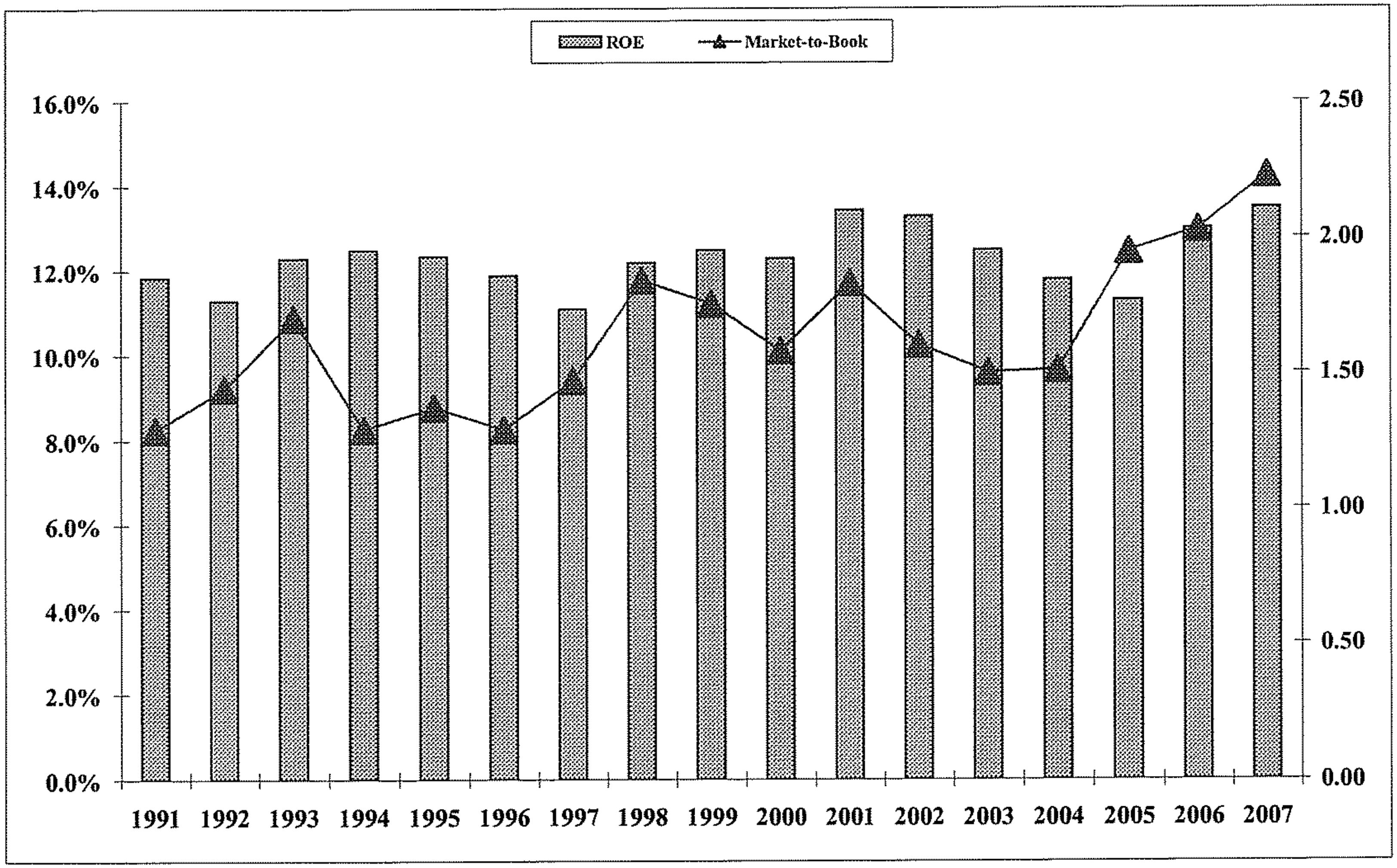
Dow Jones Utilities Dividend Yield



Data Source: Value Line Investment Survey

Exhibit JRW-4

Dow Jones Utilities - Market to Book and ROE



Data Source: Value Line Investment Survey

Exhibit JRW-5

Industry Average Betas

Industry Name	Number of Firms	Beta	Industry Name	Number of Firms	Beta	Industry Name	Number of Firms	Beta
Semiconductor	138	2.59	Telecom. Services	152	1.34	Utility (Foreign)	6	1.01
Semiconductor Equip	16	2.51	Electronics	179	1.32	Petroleum (Producing)	186	1.00
Wireless Networking	74	2.20	Investment Co.(Foreign)	15	1.31	Environmental	89	1.00
E-Commerce	56	2.08	Educational Services	39	1.27	Grocery	15	0.99
Entertainment Tech	38	2.06	Retail (Special Lines)	164	1.26	Home Appliance	11	0.95
Telecom. Equipment	124	1.98	Hotel/Gaming	75	1.25	Insurance (Life)	40	0.94
Steel (Integrated)	14	1.97	Heavy Construction	12	1.25	Electric Util. (Central)	25	0.93
Internet	266	1.97	Retail Building Supply	9	1.23	Paper/Forest Products	39	0.93
Manuf. Housing/RV	18	1.92	Railroad	16	1.23	Restaurant	75	0.93
Power	58	1.87	Industrial Services	196	1.22	Natural Gas (Div.)	31	0.93
Computers/Peripherals	144	1.86	Newspaper	18	1.21	Healthcare Information	38	0.91
Drug	368	1.78	Aerospace/Defense	69	1.19	Property Management	12	0.91
Coal	18	1.71	Metal Fabricating	37	1.19	R.E.I.T.	147	0.90
Steel (General)	26	1.71	Machinery	126	1.19	Household Products	28	0.89
Securities Brokerage	31	1.66	Chemical (Diversified)	37	1.16	Insurance (Prop/Cas.)	87	0.89
Precision Instrument	103	1.66	Financial Svcs. (Div.)	294	1.14	Beverage	44	0.89
Homebuilding	36	1.64	Office Equip/Supplies	25	1.13	Electric Utility (West)	17	0.88
Advertising	40	1.60	Packaging & Container	35	1.12	Maritime	52	0.87
Retail Automotive	16	1.58	Precious Metals	84	1.11	Apparel	57	0.87
Cable TV	23	1.56	Retail Store	42	1.11	Bank (Midwest)	38	0.85
Computer Software/Svcs	376	1.56	Furn/Home Furnishings	39	1.10	Toiletries/Cosmetics	21	0.85
Auto & Truck	28	1.54	Oilfield Svcs/Equip.	113	1.10	Electric Utility (East)	27	0.84
Recreation	73	1.54	Medical Services	178	1.10	Canadian Energy	13	0.80
Entertainment	93	1.53	Foreign Electronics	10	1.08	Food Wholesalers	19	0.79
Chemical (Basic)	19	1.52	Building Materials	49	1.07	Water Utility	16	0.78
Biotechnology	103	1.51	Pharmacy Services	19	1.07	Natural Gas Utility	26	0.78
Shoe	20	1.47	Chemical (Specialty)	90	1.06	Food Processing	123	0.77
Auto Parts	56	1.45	Metals & Mining (Div.)	78	1.05	Oil/Gas Distribution	15	0.72
Medical Supplies	274	1.43	Information Services	38	1.05	Investment Co.	18	0.71
Air Transport	49	1.40	Trucking	32	1.04	Tobacco	11	0.70
Human Resources	35	1.38	Diversified Co.	107	1.03	Bank (Canadian)	8	0.67
Publishing	40	1.35	Petroleum (Integrated)	26	1.02	Bank	504	0.63
Electrical Equipment	86	1.35	Reinsurance	11	1.01	Thrift	234	0.59
						Total/Average	7364	1.24

Data Source: http://pages stern nyu edu/~adamodar/

Exhibit JRW-6

Kentucky Utilities Company
Discounted Cash Flow Analysis

Electric Proxy Group

Dividend Yield*	4.3%
Adjustment Factor	1.0275
Adjusted Dividend Yield	4.4%
Growth Rate**	5.5%
Equity Cost Rate	9.9%

* Page 2 of Exhibit JRW-6

** Based on data provided on pages 3, 4, and 5 of Exhibit JRW-6

Exhibit JRW-6

Kentucky Utilities Company
Monthly Dividend Yields
May-October 2008

Electric Proxy Group

Company	May	June	July	Aug	Sep	Oct	Mean
ALLETE, Inc. (NYSE-ALE)	4.1%	4.0%	3.8%	4.2%	4.0%	3.8%	4.0%
Ameren Corporation (NYSE-AEE)	5.5%	5.5%	5.9%	6.3%	6.0%	6.1%	5.9%
American Electric Power Co. (NYSE-AEP)	3.7%	3.8%	3.9%	4.2%	4.3%	4.3%	4.0%
Central Vermont Public Serv. Corp. (NYSE-CV)	3.7%	4.1%	4.7%	4.4%	3.7%	3.7%	4.1%
Cleco Corporation (NYSE-CNL)	3.7%	3.6%	3.7%	3.8%	3.5%	3.4%	3.6%
DPL Inc.(NYSE-DPL)	4.0%	3.9%	3.9%	4.1%	4.5%	4.2%	4.1%
Edison International (NYSE-EIX)	2.3%	2.3%	2.4%	2.4%	2.7%	3.0%	2.5%
Empire District Electric Co. (NYSE-EDE)	5.9%	6.1%	6.4%	6.7%	5.9%	5.6%	6.1%
FirstEnergy Corporation (NYSE-FE)	2.9%	2.9%	2.8%	2.9%	3.1%	3.2%	3.0%
FPL Group, Inc. (NYSE-FPL)	2.7%	2.7%	2.7%	2.7%	2.9%	3.2%	2.8%
Hawaiian Electric Industries, Inc. (NYSE-HE)	5.0%	4.7%	4.7%	5.2%	4.9%	4.4%	4.8%
IDACORP, Inc. (NYSE-IDA)	3.7%	3.8%	3.8%	4.1%	3.9%	3.8%	3.9%
Northeast Utilities (NYSE-NU)	3.0%	3.0%	3.2%	3.5%	3.1%	3.2%	3.2%
NSTAR (NYSE-NST)	4.4%	4.2%	4.1%	4.4%	4.2%	3.9%	4.2%
Pinnacle West Capital Corp. (NYSE-PNW)	5.8%	6.2%	6.5%	6.7%	6.0%	6.0%	6.2%
PNM Resources, Inc. (NYSE-PNM)	6.7%	6.5%	6.8%	8.0%	4.2%	4.2%	6.1%
Progress Energy Inc. (NYSE-PGN)	5.8%	5.8%	5.8%	6.0%	5.6%	5.5%	5.8%
Southern Company (NYSE-SO)	4.4%	4.5%	4.8%	4.8%	4.5%	4.4%	4.6%
UIL Holdings Corporation (NYSE-UIL)	5.6%	5.5%	5.4%	5.9%	5.1%	4.9%	5.4%
UniSource Energy Corporation (NYSE-UNS)	3.6%	2.9%	2.8%	3.2%	2.9%	3.1%	3.1%
Xcel Energy Inc. (NYSE-XEL)	4.4%	4.3%	4.6%	4.8%	4.6%	4.4%	4.5%
Mean	4.3%	4.3%	4.4%	4.7%	4.3%	4.2%	4.4%

Source: *AUS Utility Reports*, monthly issues

Exhibit JRW-6

Kentucky Utilities Company
DCF Equity Cost Growth Rate Measures
***Value Line* Historic Growth Rates**

Electric Proxy Group

Company	*Value Line* Historic Growth					
	Past 10 Years			Past 5 Years		
	Earnings	Dividends	Book Value	Earnings	Dividends	Book Value
ALLETE, Inc. (NYSE-ALE)	NA	NA	NA	NA	NA	NA
Ameren Corporation (NYSE-AEE)	1.0%	0.0%	3.5%	-0.5%	0.0%	5.5%
American Electric Power Co. (NYSE-AEP)	-1.0%	-4.5%	0.0%	3.0%	-9.0%	0.0%
Central Vermont Public Serv. Corp. (NYSE-CV)	-2.5%	1.0%	1.0%	-2.5%	1.0%	2.0%
Cleco Corporation (NYSE-CNL)	2.5%	1.5%	6.5%	-2.0%	0.5%	7.0%
DPL Inc.(NYSE-DPL)	1.0%	1.5%	-0.5%	-1.0%	1.0%	2.5%
Edison International (NYSE-EIX)	7.0%	1.0%	4.5%	0.0%	0.0%	17.5%
Empire District Electric Co. (NYSE-EDE)	-1.0%	0.0%	2.0%	2.0%	0.0%	2.0%
FirstEnergy Corporation (NYSE-FE)	6.0%	2.0%	5.5%	6.0%	4.5%	4.5%
FPL Group, Inc. (NYSE-FPL)	6.0%	5.0%	6.5%	6.5%	6.5%	7.5%
Hawaiian Electric Industries, Inc. (NYSE-HE)	-0.5%	0.5%	1.5%	-3.0%	0.0%	2.0%
IDACORP, Inc. (NYSE-IDA)	-1.0%	-4.5%	3.5%	-7.0%	-8.5%	2.5%
Northeast Utilities (NYSE-NU)	11.0%	-4.5%	0.5%	8.5%	10.0%	2.5%
NSTAR (NYSE-NST)	4.5%	3.0%	3.5%	3.5%	3.5%	4.0%
Pinnacle West Capital Corp. (NYSE-PNW)	1.0%	7.0%	4.5%	-2.5%	5.5%	3.5%
PNM Resources, Inc. (NYSE-PNM)	2.0%	14.5%	5.5%	-5.0%	9.5%	5.0%
Progress Energy Inc. (NYSE-PGN)	0.0%	3.0%	6.0%	-4.5%	2.5%	3.0%
Southern Company (NYSE-SO)	3.0%	2.0%	1.0%	3.5%	2.5%	3.0%
UIL Holdings Corporation (NYSE-UIL)	-2.0%	0.0%	0.5%	-6.0%	0.0%	-1.0%
UniSource Energy Corporation (NYSE-UNS)	-5.5%	0.0%	17.5%	3.0%	15.5%	8.5%
Xcel Energy Inc. (NYSE-XEL)	-3.5%	-4.5%	-1.0%	-2.0%	-8.5%	-1.5%
Mean	1.4%	1.2%	3.6%	0.0%	1.8%	4.0%
Median	1.0%	1.0%	3.5%	-0.8%	1.0%	3.0%
Data Source: *Value Line Investment Survey, 2008*	**Average of Mean and Median F**			1.7%		

Exhibit JRW-6

Kentucky Utilities Company
DCF Equity Cost Growth Rate Measures
***Value Line* Projected Growth Rates**

Electric Proxy Group

Company	*Value Line* Projected Growth Est'd. '05-'07 to '11-'13			*Value Line* Internal Growth		
	Earnings	Dividends	Book Value	Return on Equity	Retention Rate	Internal Growth
ALLETE, Inc. (NYSE-ALE)	2.5%	5.5%	6.5%	9.5%	36.0%	3.4%
Ameren Corporation (NYSE-AEE)	3.5%	0.0%	3.0%	9.5%	28.0%	2.7%
American Electric Power Co. (NYSE-AEP)	7.5%	8.0%	6.5%	12.0%	42.0%	5.0%
Central Vermont Public Serv. Corp. (NYSE-CV)	7.5%	0.0%	3.5%	7.5%	43.0%	3.2%
Cleco Corporation (NYSE-CNL)	10.5%	9.5%	6.0%	11.0%	37.0%	4.1%
DPL Inc.(NYSE-DPL)	11.0%	5.0%	9.0%	19.0%	43.0%	8.2%
Edison International (NYSE-EIX)	5.0%	7.0%	9.0%	11.5%	61.0%	7.0%
Empire District Electric Co. (NYSE-EDE)	10.0%	1.5%	3.5%	10.5%	29.0%	3.0%
FirstEnergy Corporation (NYSE-FE)	11.0%	8.5%	7.5%	15.5%	55.0%	8.5%
FPL Group, Inc. (NYSE-FPL)	9.5%	7.5%	8.5%	13.0%	54.0%	7.0%
Hawaiian Electric Industries, Inc. (NYSE-HE)	7.5%	1.0%	2.5%	11.5%	33.0%	3.8%
IDACORP, Inc. (NYSE-IDA)	2.0%	0.0%	2.0%	7.5%	47.0%	3.5%
Northeast Utilities (NYSE-NU)	11.5%	6.0%	5.5%	8.5%	52.0%	4.4%
NSTAR (NYSE-NST)	7.5%	7.0%	5.5%	14.5%	38.0%	5.5%
Pinnacle West Capital Corp. (NYSE-PNW)	2.0%	2.0%	2.0%	8.0%	27.0%	2.2%
PNM Resources, Inc. (NYSE-PNM)	-1.0%	1.5%	0.0%	6.0%	30.0%	1.8%
Progress Energy Inc. (NYSE-PGN)	5.0%	1.0%	1.5%	9.5%	25.0%	2.4%
Southern Company (NYSE-SO)	5.5%	4.5%	6.0%	14.0%	32.0%	4.5%
UIL Holdings Corporation (NYSE-UIL)	4.5%	0.0%	1.0%	10.5%	20.0%	2.1%
UniSource Energy Corporation (NYSE-UNS)	2.0%	6.5%	3.5%	7.5%	32.0%	2.4%
Xcel Energy Inc. (NYSE-XEL)	7.5%	3.0%	4.5%	11.0%	47.0%	5.2%
Mean	6.3%	4.0%	4.6%	10.8%	38.6%	4.2%
Median	7.5%	4.5%	4.5%	10.5%	37.0%	3.9%
Average of Mean and Median Figures =		5.2%			Average =	4.0%

Data Source: *Value Line Investment Survey, 2008*

Exhibit JRW-6

Kentucky Utilities Company
DCF Equity Cost Growth Rate Measures
Analysts Projected EPS Growth Rate Estimates

Electric Proxy Group

		Bloomberg		Zack's		
Company	Sym	Mean	# Estimates	Mean	# Estimates	Average
ALLETE, Inc. (NYSE-ALE)	ALE	7.50%	2	5.00%	1	6.25%
Ameren Corporation (NYSE-AEE)	AEE	6.50%	2	5.00%	5	5.75%
American Electric Power Co. (NYSE-AEP)	AEP	4.95%	4	6.25%	4	5.60%
Central Vermont Public Serv. Corp. (NYSE-CV)	CV	-	0	-	-	-
Cleco Corporation (NYSE-CNL)	CNL	14.14%	2	14.00%	1	14.07%
DPL Inc.(NYSE-DPL)	DPL	13.95%	2	10.67%	3	12.31%
Edison International (NYSE-EIX)	EIX	8.25%	5	8.00%	3	8.13%
Empire District Electric Co. (NYSE-EDE)	EDE	34.00%	1	-	-	34.00%
FirstEnergy Corporation (NYSE-FE)	FE	9.00%	3	8.33%	3	8.67%
FPL Group, Inc. (NYSE-FPL)	FPL	9.83%	7	9.97%	6	9.90%
Hawaiian Electric Industries, Inc. (NYSE-HE)	HE	2.75%	2	4.17%	3	3.46%
IDACORP, Inc. (NYSE-IDA)	IDA	6.00%	2	6.00%	2	6.00%
Northeast Utilities (NYSE-NU)	NU	7.02%	5	10.00%	3	8.51%
NSTAR (NYSE-NST)	NST	6.33%	3	6.75%	4	6.54%
Pinnacle West Capital Corp. (NYSE-PNW)	PNW	4.67%	3	6.67%	3	5.67%
PNM Resources, Inc. (NYSE-PNM)	PNM	10.16%	5	6.00%	4	8.08%
Progress Energy Inc. (NYSE-PGN)	PGN	5.02%	5	5.00%	6	5.01%
Southern Company (NYSE-SO)	SO	5.50%	4	5.00%	5	5.25%
UIL Holdings Corporation (NYSE-UIL)	UIL	6.00%	1	6.00%	1	6.00%
UniSource Energy Corporation (NYSE-UNS)	UNS	-	0	-	-	-
Xcel Energy Inc. (NYSE-XEL)	XEL	6.00%	4	6.00%	4	6.00%
Median		6.50%	3.0	6.13%	3.0	6.25%

Source:Bloomberg - October 20, 2008

Source:Bloomberg Sept. 2008

Exhibit JRW-7

Capital Asset Pricing Model

Electric Proxy Group

Risk-Free Interest Rate	**4.50%**
Beta*	**0.82**
Ex Ante Equity Risk Premium**	**4.56%**
CAPM Cost of Equity	**8.2%**

* See page 2 of Exhibit JRW-7

** See page 3 of Exhibit JRW-7

Exhibit JRW-7

Kentucky Utilities Company
Beta

Electric Proxy Group

Company	Beta
ALLETE, Inc. (NYSE-ALE)	0.90
Ameren Corporation (NYSE-AEE)	0.80
American Electric Power Co. (NYSE-AEP)	0.85
Central Vermont Public Serv. Corp. (NYSE-CV)	1.05
Cleco Corporation (NYSE-CNL)	1.00
DPL Inc.(NYSE-DPL)	0.80
Edison International (NYSE-EIX)	0.90
Empire District Electric Co. (NYSE-EDE)	0.85
FirstEnergy Corporation (NYSE-FE)	0.75
FPL Group, Inc. (NYSE-FPL)	0.80
Hawaiian Electric Industries, Inc. (NYSE-HE)	0.75
IDACORP, Inc. (NYSE-IDA)	0.90
Northeast Utilities (NYSE-NU)	0.75
NSTAR (NYSE-NST)	0.80
Pinnacle West Capital Corp. (NYSE-PNW)	0.80
PNM Resources, Inc. (NYSE-PNM)	0.85
Progress Energy Inc. (NYSE-PGN)	0.75
Southern Company (NYSE-SO)	0.65
UIL Holdings Corporation (NYSE-UIL)	0.80
UniSource Energy Corporation (NYSE-UNS)	0.75
Xcel Energy Inc. (NYSE-XEL)	0.80
Mean	0.82

Data Source: *Value Line Investment Survey, 2008*

Exhibit JRW-7

Kentucky Utilities Company
Capital Asset Pricing Model
Equity Risk Premium

Category	Study Authors	Publication Date	Time Period Of Study	Methodology	Return Measure	Range Low	Range High	Midpoint of Range	Mean	Average
Historical Risk Premium										
	Ibbotson	2008	1926-2007	Historical Stock Returns - Bond Returns	Arithmetic				6.50%	
					Geometric				4.90%	
	Bate	2008	1900-2007	Historical Stock Returns - Bond Returns	Geometric				4.50%	
	Shiller	2006	1926-2005	Historical Stock Returns - Bond Returns	Arithmetic				7.00%	
					Geometric				5.50%	
	Damodoran	2006	1926-2005	Historical Stock Returns - Bond Returns	Arithmetic				6.70%	
					Geometric				5.10%	
	Siegel	2005	1926-2005	Historical Stock Returns - Bond Returns	Arithmetic				6.10%	
					Geometric				4.60%	
	Dimson, Marsh, and Staunton	2006	1900-2005	Historical Stock Returns - Bond Returns	Arithmetic				5.50%	
	Goyal & Welch	2006	1872-2004	Historical Stock Returns - Bond Returns					4.77%	
	AVERAGE									5.56%
Ex Ante Models (Puzzle Research)										
	Claus Thomas	2001	1985-1998	Abnormal Earnings Model					3.00%	
	Arnott and Bernstein	2002	1810-2001	Fundamentals - Div Yld + Growth					2.40%	
	Constantinides	2002	1872-2000	Historical Returns & Fundamentals - P/D & P/E					6.90%	
	Cornell	1999	1926-1997	Historical Returns & Fundamental GDP/Earnings		3.50%	5.50%	4.50%	4.50%	
	Easton, Taylor, et al	2002	1981-1998	Residual Income Model					5.30%	
	Fama French	2002	1951-2000	Fundamental DCF with EPS and DPS Growth		2.55%	4.32%		3.44%	
	Harris & Marston	2001	1982-1998	Fundamental DCF with Analysts' EPS Growth					7.14%	
	Best & Byrne	2001								
	McKinsey	2002	1962-2002	Fundamental (P/E, D/P, & Earnings Growth)		3.50%	4.00%		3.75%	
	Siegel	2005	1802-2001	Historical Earnings Yield	Geometric				2.50%	
	Grabowski	2006	1926-2005	Historical and Projected		3.50%	6.00%	4.75%	4.75%	
	Maheu & McCurdy	2006	1885-2003	Historical Excess Returns, Structural Breaks,		4.02%	5.10%	4.56%	4.56%	
	Bostock	2004	1960-2002	Bond Yields, Credit Risk, and Income Volatility		3.90%	1.30%	2.60%	2.60%	
	Bakshi & Chen	2005	1982-1998	Fundamentals - Interest Rates					7.31%	
	Donaldson, Kamstra, & Kramer	2006	1952-2004	Fundamental, Dividend yld., Returns,, & Volatility		3.00%	4.00%	3.50%	3.50%	
	Campbell	2008	1982-2007	Historical & Projections (D/P & Earnings Growth)		4.10%	5.40%		4.75%	
	Best & Byrne	2001	Projection	Fundamentals - Div Yld + Growth					2.00%	
	Fernandez	2007	Projection	Required Equity Risk Premium					4.00%	
	DeLong & Magin	2008	Projection	Earnings Yield - TIPS					3.22%	
	Damodoran	2008	Projection	Fundamentals - Implied from FCF to Equity Model					4.37%	
	Social Security									
	Office of Chief Actuary		1900-1995							
	John Campbell	2001	1860-2000	Historical & Projections (D/P & Earnings Growth)	Arithmetic	3.00%	4.00%	3.50%	3.50%	
			Projected for 75 Years		Geometric	1.50%	2.50%	2.00%	2.00%	
	Peter Diamond	2001	Projected for 75 Years	Fundamentals (D/P, GDP Growth)		3.00%	4.80%	3.90%	3.90%	
	John Shoven	2001	Projected for 75 Years	Fundamentals (D/P, P/E, GDP Growth)		3.00%	3.50%	3.25%	3.25%	
	AVERAGE									4.03%
Surveys										
	Survey of Financial Forecasters	2008	10-Year Projection	About 50 Financial Forecastsers					1.96%	
	Duke - CFO Magazine Survey	2008	10-Year Projection	Approximately 500 CFOs					3.99%	
	Welch - Academics	2008	30-Year Projection	Random Academics		5.00%	5.74%		5.37%	
	AVERAGE									3.77%
Building Block										
	Ibbotson and Chen	2008	1926-2007	Historical Supply Model (D/P & Earnings Growth)	Arithmetic			6.23%	5.24%	
					Geometric			4.24%		
	Woolridge		2008	Current Supply Model (D/P & Earnings Growth)					4.54%	
	AVERAGE									4.89%
OVERALL AVERAGE										4.56%

Exhibit JRW-7

Kentucky Utilities Company

Survey of Professional Forecasters
Philadelphia Federal Reserve Bank
Long-Term Forecasts

Table Seven
LONG-TERM (10 YEAR) FORECASTS

SERIES: CPI INFLATION RATE		SERIES: REAL GDP GROWTH RATE	
STATISTIC		STATISTIC	
MINIMUM	1.600	MINIMUM	2.200
LOWER QUARTILE	2.200	LOWER QUARTILE	2.500
MEDIAN	2.500	MEDIAN	2.750
UPPER QUARTILE	2.750	UPPER QUARTILE	2.800
MAXIMUM	4.200	MAXIMUM	3.100
MEAN	2.520	MEAN	2.700
STD. DEV.	0.520	STD. DEV.	0.230
N	45	N	43
MISSING	5	MISSING	7

SERIES: PRODUCTIVITY GROWTH		SERIES: STOCK RETURNS (S&P 500)	
STATISTIC		STATISTIC	
MINIMUM	0.900	MINIMUM	2.700
LOWER QUARTILE	1.800	LOWER QUARTILE	6.000
MEDIAN	2.000	MEDIAN	6.500
UPPER QUARTILE	2.200	UPPER QUARTILE	8.000
MAXIMUM	3.000	MAXIMUM	9.000
MEAN	2.000	MEAN	6.800
STD. DEV.	0.390	STD. DEV.	1.300
N	39	N	31
MISSING	11	MISSING	19

SERIES: BOND RETURNS (10-YEAR)		SERIES: BILL RETURNS (3-MONTH)	
STATISTIC		STATISTIC	
MINIMUM	3.200	MINIMUM	2.400
LOWER QUARTILE	4.500	LOWER QUARTILE	3.000
MEDIAN	5.000	MEDIAN	4.000
UPPER QUARTILE	5.200	UPPER QUARTILE	4.250
MAXIMUM	5.800	MAXIMUM	5.300
MEAN	4.840	MEAN	3.840
STD. DEV.	0.590	STD. DEV.	0.680
N	38	N	38
MISSING	12	MISSING	12

Source: Philadelphia Federal Researve Bank, Survey of Professional Forecasters, February 12, 2008
http://www.phil.frb.org/files/spf/spfq107.pdf

Exhibit JRW-7

Kentucky Utilities Company
CAPM
Real S&P 500 EPS Growth Rate

Year	S&P 500 EPS	Annual Inflation CPI	Inflation Adjustment Factor	Real S&P 500 EPS	
1960	3.10	1.48		3.10	
1961	3.37	0.07	1.01	3.35	
1962	3.67	1.22	1.02	3.59	
1963	4.13	1.65	1.04	3.99	
1964	4.76	1.19	1.05	4.55	
1965	5.30	1.92	1.07	4.97	
1966	5.41	3.35	1.10	4.90	
1967	5.46	3.04	1.14	4.80	
1968	5.72	4.72	1.19	4.81	
1969	6.10	6.11	1.26	4.83	10-Year
1970	5.51	5.49	1.34	4.13	2.89%
1971	5.57	3.36	1.38	4.04	
1972	6.17	3.41	1.43	4.33	
1973	7.96	8.80	1.55	5.13	
1974	9.35	12.20	1.74	5.37	
1975	7.71	7.01	1.86	4.14	
1976	9.75	4.81	1.95	4.99	
1977	10.87	6.77	2.08	5.22	
1978	11.64	9.03	2.27	5.13	
1979	14.55	13.31	2.57	5.66	10-Year
1980	14.99	12.40	2.89	5.18	2.30%
1981	15.18	8.94	3.15	4.82	
1982	13.82	3.87	3.27	4.23	
1983	13.29	3.80	3.40	3.91	
1984	16.84	3.95	3.53	4.77	
1985	15.68	3.77	3.66	4.28	
1986	14.43	1.13	3.70	3.90	
1987	16.04	4.41	3.87	4.15	
1988	22.77	4.42	4.04	5.64	
1989	24.03	4.65	4.22	5.69	10-Year
1990	21.73	6.11	4.48	4.85	-0.65%
1991	19.10	3.06	4.62	4.14	
1992	18.13	2.90	4.75	3.81	
1993	19.82	2.75	4.88	4.06	
1994	27.05	2.67	5.01	5.40	
1995	35.35	2.54	5.14	6.88	
1996	35.78	3.32	5.31	6.74	
1997	39.56	1.70	5.40	7.33	
1998	38.23	1.61	5.48	6.97	
1999	45.17	2.68	5.63	8.02	10-Year
2000	52.00	3.39	5.82	8.93	6.29%
2001	44.23	1.55	5.92	7.48	
2002	47.24	2.38	6.06	7.80	
2003	54.15	1.88	6.17	8.77	
2004	67.01	3.26	6.37	10.51	5-Year
2005	68.32	3.42	6.60	10.35	3.00%
2006	81.96	2.54	6.77	12.11	
2007	87.51	4.08	7.04	12.43	
Data Source: http://pages.stern.nyu.edu/~adamodar/				Real EPS Growth	**3.0%**

Exhibit JRW-8
Kentucky Utilities Company
Financial Performance Indicators - Dr. Avera's Non-Utility and Utility Proxy Groups

Non-Utility Proxy Group

Company Name	Return on Common Equity	Price To Book Value	Fixed Asset Turnover	Common Equity Ratio
3M Company	34.86	3.47	3.72	74.50
Abbott Labs.	24.91	5.01	3.45	65.20
Aflac Inc.	18.37	2.45		85.70
Allergan Inc.	15.38	3.46	5.74	70.20
Allstate Corp	21.21	0.80		79.50
Anheuser-Busch	67.11	14.35	1.89	25.60
Automatic Data Proc	19.83	3.68	10.78	99.20
Bank of America	10.39	0.78		41.40
Bard (C.R.)	21.99	4.42	6.39	92.50
Becton Dickinson	22.42	4.04	2.55	82.00
Brown-Forman 'B'	25.50	4.25	5.15	80.50
Coca-Cola	27.50	4.95	3.40	86.90
Colgate-Palmolive	86.54	17.39	4.57	37.90
Commerce Bancshs.	13.52	2.08		72.40
Fortune Brands	14.09	1.09	5.04	59.00
Gannett Co.	11.38	0.28	2.84	68.80
Gen'l Electric	19.44	1.74	2.22	26.60
Gen'l Mills	19.76	3.55	4.39	58.80
Genuine Parts	18.63	2.15	25.45	91.60
Heinz (H.J.)	44.75	7.29	4.78	28.50
Hormel Foods	15.78	2.17	6.41	84.30
Johnson & Johnson	27.89	4.22	4.31	86.00
Kimberly-Clark	35.63	4.99	2.26	54.30
Kraft Foods	10.64	1.66	3.46	67.90
Lilly (Eli)	28.27	2.83	2.17	74.80
Lockheed Martin	29.60	3.88	9.69	69.50
Medtronic Inc.	25.87	4.04	6.09	66.50
Meredith Corp.	20.26	1.12	7.84	69.00
NIKE Inc. 'B'	22.16	3.75	9.85	94.70
Northrop Grumman	9.81	0.91	6.79	80.60
PepsiCo Inc.	32.22	5.31	3.52	80.20
Pfizer Inc.	23.51	1.80	3.08	89.80
Procter & Gamble	17.46	2.90	4.05	73.20
Sigma-Aldrich	19.24	3.87	2.99	88.60
Sysco Corp.	32.44	4.58	12.98	63.30
Tootsie Roll Ind.	8.08	2.02	2.45	98.80
Torchmark Corp.	15.70	0.98		82.10
United Parcel Serv.	35.86	4.42	2.81	61.90
Walgreen Co.	18.38	2.19	6.56	100.00
Wal-Mart Stores	19.94	3.34	3.86	65.90
Washington Federal	10.24	1.14		100.00
Washington Post	8.33	0.97	3.26	89.30
Weis Markets	7.05	1.26	4.64	100.00
Average	23.53	3.53	5.44	73.66

Data Source: *Value Line Investment Analyzer*

Utility Proxy Group

Company Name	Return on Common Equity	Price To Book Value	Fixed Asset Turnover	Common Equity Ratio
ALLETE	11.79	1.55	0.76	64.40
Alliant Energy	11.26	1.37	0.73	61.90
Consol. Edison	10.43	1.32	0.66	53.10
Constellation Energy	14.66	0.86	2.17	52.40
Dominion Resources	14.86	2.39	0.73	41.10
Duke Energy	7.18	0.99	0.41	69.10
Entergy Corp.	14.42	2.23	0.55	43.90
Exelon Corp	26.89	3.59	0.78	45.70
Integrys Energy	5.49	1.12	2.31	58.30
MDU Resources	12.80	1.48	1.16	68.40
PG&E Corp.	11.66	1.55	0.56	50.40
Public Serv. Enterpris	18.07	2.17	0.97	45.50
SCANA Corp.	10.81	1.40	0.61	49.70
Sempra Energy	13.51	1.36	0.77	63.70
Vectren Corp.	11.59	1.48	0.90	49.80
Wisconsin Energy	10.85	1.56	0.55	49.20
Xcel Energy Inc.	9.07	1.23	0.60	49.40
Average	12.67	1.63	0.90	53.88

THE WALL STREET JOURNAL.

Study Suggests Bias in Analysts' Rosy Forecasts

By ANDREW EDWARDS
March 21, 2008; Page C6

Despite an economy teetering on the brink of a recession -- if not already in one -- analysts are still painting a rosy picture of earnings growth, according to a study done by Penn State's Smeal College of Business.

The report questions analysts' impartiality five years after then-New York Attorney General Eliot Spitzer forced analysts to pay $1.5 billion in damages after finding evidence of bias.

"Wall Street analysts basically do two things: recommend stocks to buy and forecast earnings," said J. Randall Woolridge, professor of finance. "Previous studies suggest their stock recommendations do not perform well, and now we show that their long-term earnings-per-share growth-rate forecasts are excessive and upwardly biased."

The report, which examined analysts' long-term (three to five years) and one-year per-share earnings expectations from 1984 through 2006 found that companies' long-term earnings growth surpassed analysts' expectations in only two instances, and those came right after recessions.

Over the entire time period, analysts' long-term forecast earnings-per-share growth averaged 14.7%, compared with actual growth of 9.1%. One-year per-share earnings expectations were slightly more accurate. The average forecast was for 13.8% growth and the average actual growth rate was 9.8%.

"A significant factor in the upward bias in long-term earnings-rate forecasts is the reluctance of analysts to forecast" profit declines, Mr. Woolridge said. The study found that nearly one-third of all companies experienced profit drops over successive three-to-five-year periods, but analysts projected drops less than 1% of the time.

The study's authors said, "Analysts are rewarded for biased forecasts by their employers, who want them to hype stocks so that the brokerage house can garner trading commissions and win underwriting deals."

They also concluded that analysts are under pressure to hype stocks to generate trading commissions, and they often don't follow stocks they don't like.

Write to Andrew Edwards at andrew.edwards@dowjones.com

Growth Rates
GNP, S&P 500 Price, EPS, and DPS

	GDP	S&P 500	Earnings	Dividends	
1960	526.4	58.11	3.10	1.98	
1961	544.7	71.55	3.37	2.04	
1962	585.6	63.1	3.67	2.15	
1963	617.7	75.02	4.13	2.35	
1964	663.6	84.75	4.76	2.58	
1965	719.1	92.43	5.30	2.83	
1966	787.8	80.33	5.41	2.88	
1967	832.6	96.47	5.46	2.98	
1968	910.0	103.86	5.72	3.04	
1969	984.6	92.06	6.10	3.24	
1970	1038.5	92.15	5.51	3.19	
1971	1127.1	102.09	5.57	3.16	
1972	1238.3	118.05	6.17	3.19	
1973	1382.7	97.55	7.96	3.61	
1974	1500.0	68.56	9.35	3.72	
1975	1638.3	90.19	7.71	3.73	
1976	1825.3	107.46	9.75	4.22	
1977	2030.9	95.1	10.87	4.86	
1978	2294.7	96.11	11.64	5.18	
1979	2563.3	107.94	14.55	5.97	
1980	2789.5	135.76	14.99	6.44	
1981	3128.4	122.55	15.18	6.83	
1982	3255.0	140.64	13.82	6.93	
1983	3536.7	164.93	13.29	7.12	
1984	3933.2	167.24	16.84	7.83	
1985	4220.3	211.28	15.68	8.20	
1986	4462.8	242.17	14.43	8.19	
1987	4739.5	247.08	16.04	9.17	
1988	5103.8	277.72	22.77	10.22	
1989	5484.4	353.4	24.03	11.73	
1990	5803.1	330.22	21.73	12.35	
1991	5995.9	417.09	19.10	12.97	
1992	6337.7	435.71	18.13	12.64	
1993	6657.4	466.45	19.82	12.69	
1994	7072.2	459.27	27.05	13.36	
1995	7397.7	615.93	35.35	14.17	
1996	7816.9	740.74	35.78	14.89	
1997	8304.3	970.43	39.56	15.52	
1998	8747.0	1229.23	38.23	16.20	
1999	9268.4	1469.25	45.17	16.71	
2000	9817.0	1320.28	52.00	16.27	
2001	10128.0	1148.09	44.23	15.74	
2002	10469.6	879.82	47.24	16.08	
2003	10960.8	1111.91	54.15	17.88	
2004	11685.9	1211.92	67.01	19.41	
2005	12433.9	1248.29	68.32	22.38	**Average**
2006	13194.7	1418.3	81.96	25.05	
2007	13843.0	1468.36	87.51	27.73	
Growth	**7.20%**	**7.11%**	**7.36%**	**5.77%**	**6.86%**

Data Sources: GDPA - http://research.stlouisfed.org/fred2/categories/106
S&P 500, EPS and DPS - http://pages.stern.nyu.edu/~adamodar/

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF KENTUCKY UTILITIES COMPANY, INC. FOR AN ADJUSTMENT OF BASE RATES	)))	Case No. 2008-00251 C/W Case No. 2007-00565

AFFIDAVIT OF DR. J. RANDALL WOOLRIDGE

Commonwealth of)
Pennsylvania)
)
)

Dr. J. Randall Woolridge, being first duly sworn, states the following: The prepared Pre-Filed Direct Testimony, and the Schedules and Appendix attached thereto constitute the direct testimony of Affiant in the above-styled case. Affiant states that he would give the answers set forth in the Pre-Filed Direct Testimony if asked the questions propounded therein. Affiant further states that, to the best of his knowledge, his statements made are true and correct. Further affiant saith not

Dr. J. Randall Woolridge

Dr. J. Randall Woolridge

SUBSCRIBED AND SWORN to before me this 30 day of October, 2008

Mary L. Hart
NOTARY PUBLIC

My Commission Expires: NOTARIAL SEAL
Mary L. Hart, Notary Public
State College Boro., Centre County
My commission expires August 25, 2009

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF KENTUCKY UTILITIES COMPANY FOR AN ADJUSTMENT OF ELECTRIC BASE RATES	)))	**Case No. 2008-00251 C/W Case No. 2007-00565**

Direct Testimony of
Michael J. Majoros, Jr.

on Behalf of
the Office of the Attorney General

October 28, 2008

TABLE OF CONTENTS

I. Introduction

Q. State your name, position, and business address.

A. My name is Michael J. Majoros, Jr. I am Vice President of Snavely King Majoros O'Connor & Lee, Inc. ("Snavely King"), located at 1111 14th Street, N.W., Suite 300, Washington, D.C. 20005.

Q. Describe Snavely King.

A. Snavely King is an economic consulting firm founded in 1970 to conduct research on a consulting basis into the rates, revenues, costs, and economic performance of regulated firms and industries. Snavely King represents the interests of government agencies, businesses, and individuals who are consumers of telecom, public utility, and transportation services.

We have a professional staff of twelve economists, accountants, engineers and cost analysts. Most of our work involves the development, preparation, and presentation of expert witness testimony before Federal and state regulatory agencies. Over the course of our 37-year history, members of the firm have participated in more than 1,000 proceedings before almost all of the state commissions and all Federal commissions that regulate utilities or transportation industries.

Q. Have you prepared a summary of your qualifications and experience?

A. Yes, Appendix A is a summary of my qualifications and experience. Appendix B contains a tabulation of my appearances as an expert witness before state and Federal regulatory agencies.

Q. For whom are you appearing in this proceeding?

A. I am appearing on behalf of the Attorney General of the Commonwealth of Kentucky ("AG").

II. Subject of Testimony

Q. What is the subject of your testimony?

A. My testimony addresses depreciation, specifically the Companies' regulatory liabilities for cost of removal.

Q. Are you the same Michael J. Majoros, Jr. who submitted testimony in Case Nos. 2007-00564 and 2007-00565, Louisville Gas and Electric Company and Kentucky Utilities' ("LG&E," "KU," or, collectively "the Companies") recent depreciation study filings?

A. Yes, I am. In those cases I reviewed the Companies' depreciation proposals and submitted my own recommended depreciation rates. My recommended rates have been incorporated by Attorney General witness Robert Henkes in his depreciation adjustment in the instant cases.

III. Cost of Removal Regulatory Liability

Q. What is the cost of removal regulatory liability?

A. The cost of removal regulatory liability is the amount of money the Companies have collected over time for cost of removal, less any amount expended for that purpose. The Financial Accounting Standards Board's (FASB) Statement of Financial Accounting Standard No. 143 ("SFAS No. 143") requires these amounts to be shown as a regulatory liability for GAAP purposes. For ratemaking purposes the amounts are included in accumulated depreciation. Unless the state regulatory body takes action, these amounts are not specifically recognized as regulatory liabilities for ratemaking purposes.

Q. Did you discuss the Companies' cost of removal regulatory liabilities in your testimony in Case Nos. 2007-00564 and 2007-00565?

A. Yes. I discussed the liabilities briefly on pages 18 and 19 of my direct testimony in those cases, and noted that as of December 31, 2007, KU and LG&E had reported $291.6 million and $241 million cost of removal regulatory liabilities, respectively.[1] I also noted the following growth of these regulatory liabilities:

> These regulatory liabilities have increased by $56.5 million (KU) and $33.1 million (LG&E), from the amounts I highlighted in Case Nos. 2003-00433 and 2003-00434. In other words, just since their last rate cases, the Companies have collected almost $90 million more from ratepayers than they have spent on actual cost of removal.[2]

Q. Did you make any recommendations in those cases regarding the cost of removal regulatory liabilities?

A. No, I did not. Although I normally would make recommendations regarding the cost of removal regulatory liability, in Case Nos. 2007-00564 and 2007-00565 I chose to focus instead on the Companies' unnecessary switch to the ELG procedure and the inclusion of future inflation in their cost of removal estimates.

Q. What do you normally recommend regarding the cost of removal regulatory liability?

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[1] Note that since the Companies became subsidiaries of E.ON, they are no longer required to file reports with the SEC. The most recent SEC financial reports available are as of September 30, 2006. 2007 amounts provided in responses to AG 1-100 (LG&E), 1-93 and 2-6 (KU). KU amount is KY jurisdictional.

[2] Majoros Direct Testimony, Case Nos. 2007-00564 and 2007-00565, page 19. Footnote deleted.

A. In most cases I recommend that this liability be reclassified from accumulated depreciation to Account 254 - Other Regulatory Liabilities for regulatory accounting, reporting and ratemaking purposes. Based on the policy decisions of some consumer advocate clients, I have also recommended that the regulatory liability be returned to ratepayers through a specific amortization period.

Q. Have you made similar recommendations before the Kentucky Public Service Commission ("KPSC")?

A. Yes. In KU and LG&E's most recent rate cases, Case Nos. Nos. 2003-00433 and 2003-00434 I recommended that the existing cost of removal reserve be amortized back to ratepayers in the post-hearing brief.[3] The Commission rejected my recommendation.[4] More recently, I proposed the establishment of a regulatory liability for ratemaking purposes in Case No. 2005-00042 regarding Union Light, Heat and Power Company. The proposal was not accepted.[5]

Q. Why have you brought up the issue in this case?

A. I have brought the issue up because Staff explicitly asked the Companies about it during discovery. Staff Third Data Request Question No. 21(c) (LG&E) and No. 22(c) (KU) asked the Company to "describe all favorable and unfavorable consequences to [LG&E/KU] if the Commission were to require reclassification of [LG&E's/KU's] asset removal costs from accumulated depreciation to a

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[3] Orders, Case Nos. 2003-00433, pages 29-30 and 2003-00434, page 25.
[4] Orders, Case Nos. 2003-00433 and 2003-00434, pages 32 and 27, respectively.
[5] Case No. 2005-00042, Order issued December 22, 2005, p. 39.

regulatory liability account for regulatory reporting purposes."[6] I have quoted LG&E's response below. KU provided a similar response.

> If the Commission were to require the reclassification of LG&E's costs of removal from accumulated depreciation to a regulatory liability account for regulatory reporting purposes, a favorable consequence would be that it would create consistency between GAAP reporting and regulatory reporting. An unfavorable consequence would be the inconsistency that would be created with prior years' regulatory reporting. There would be no impact on the ratemaking treatment of the costs of removal, regardless of where they are recorded, since a basic concept behind including cost of removal as a component of depreciation rates is to prevent generational inequities. No other consequences have been identified by LG&E.[7]

Q. What is your opinion of the Companies' responses?

A. The responses indicate that even LG&E and KU agree there are no real consequences of reclassifying the cost of removal regulatory liabilities from accumulated depreciation to a regulatory liability account for ratemaking purposes. The alleged consequence of "inconsistency with prior reporting" does not have merit in this case. After all, the requirement to reclassify the amounts for GAAP purposes only came into being relatively recently, with the implementation of SFAS No. 143 in 2003. Because the FERC declined to require the reclassification for regulatory purposes an inconsistency developed between the GAAP and regulatory books. Furthermore, the Companies obviously do not shy away from accounting changes, as evident by their proposed unnecessary switch from ALG to ELG for computing depreciation rates – a procedure change

[6] Staff 3rd Data Request, Qs. 21(c) (LG&E) and 22(c) (KU). Note that KU was initially asked the question in Staff's 2nd Data Request, Q. 98(c) but did not address the question to Staff's satisfaction.
[7] Staff 3rd Data Request, Q. 21(c) (LG&E).

that would cause a $34.6 million increase to depreciation expense, all other things being equal.[8]

Q. Do you see any favorable consequences of the reclassification that the Companies failed to mention?

A. Yes. As I mentioned earlier, because E.ON does not file 10-K reports with the SEC, these amounts are no longer publicly available. Absent a specific request for the amount in a proceeding such as a rate case, the Commission will not know how much the Companies have collected for cost of removal over and above what they have spent. Reclassification would allow the Commission to track these amounts. Reclassification would also protect ratepayer interests in these amounts. Without that protection, current and future ratepayers face the strong possibility of losing substantial prepaid funds they have submitted to the Company for future cost of removal. LG&E, KU and virtually all other utilities, consider amounts in accumulated depreciation, even excessive amounts, to be *their* money, i.e. capital recovery with no refund obligation. It is certainly fair and reasonable for any Commission to recognize excessive cost of removal collections as a refundable regulatory liability until the utility spends them on their intended purpose.

Q. Have any other Commissions recognized non-legal asset retirement obligations as regulatory liabilities?

A. Yes. Recently, in Application No. 04-12-014, involving Southern California Edison Company, the California Public Utilities Commission specifically

[8] Majoros Direct Testimony, Case Nos. 2007-00564 and 2007-00565, page 12.

recognized that Company's non-legal asset retirement obligations collections as a regulatory liability.[9]

IV. Recommendation

Q. What do you recommend?

A: I recommend that the Commission specifically recognize LG&E and KU's regulatory liabilities for cost of removal as reported on their GAAP statements as regulatory liabilities for ratemaking purposes. The Companies should be required to report these amounts and reclassify them from accumulated depreciation to Account 254-Other Regulatory Liabilities for regulatory accounting, reporting and ratemaking purposes. This will result in equivalent GAAP and regulatory accumulated depreciation and regulatory liability amounts for "non-legal" cost of removal.[10]

Q. Does this change have any revenue requirement effect?

A. No, it is merely a revenue neutral reclassification of a rate base reduction from one account to another.

Q. Does this conclude your testimony?

A. Yes, it does.

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[9] Southern California Edison 2006 GRC, Application No. 04-12-014, Decision 06-05-016, issued May 11, 2006, p. 204:16.7.1.

[10] The phrase "non-legal" emanates from the FERC's Order No. 631. It is used to distinguish legally required asset retirement obligations from those which lead to the cost of removal regulatory liability discussed above. Importantly, the phrase "non-legal" should not be construed to imply any "illegality."

Experience

Snavely King Majoros O'Connor & Lee, Inc.

Vice President and Treasurer (1988 to Present)
Senior Consultant (1981-1987)

Mr. Majoros provides consultation specializing in accounting, financial, and management issues. He has testified as an expert witness or negotiated on behalf of clients in more than one hundred thirty regulatory federal and state regulatory proceedings involving telephone, electric, gas, water, and sewerage companies. His testimony has encompassed a wide array of complex issues including taxation, divestiture accounting, revenue requirements, rate base, nuclear decommissioning, plant lives, and capital recovery. Mr. Majoros has also provided consultation to the U.S. Department of Justice and appeared before the U.S. EPA and the Maryland State Legislature on matters regarding the accounting and plant life effects of electric plant modifications and the financial capacity of public utilities to finance environmental controls. He has estimated economic damages suffered by black farmers in discrimination suits.

Van Scoyoc & Wiskup, Inc., *Consultant (1978-1981)*

Mr. Majoros conducted and assisted in various management and regulatory consulting projects in the public utility field, including preparation of electric system load projections for a group of municipally and cooperatively owned electric systems; preparation of a system of accounts and reporting of gas and oil pipelines to be used by a state regulatory commission; accounting system analysis and design for rate proceedings involving electric, gas, and telephone utilities. Mr. Majoros provided onsite management accounting and controllership assistance to a municipal electric and water utility. Mr. Majoros also assisted in an antitrust proceeding involving a major electric utility. He submitted expert testimony in FERC Docket No. RP79-12 (El Paso Natural Gas Company), and he co-authored a study entitled Analysis of Staff Study on Comprehensive Tax Normalization that was submitted to FERC in Docket No. RM 80-42.

Handling Equipment Sales Company, Inc.
Controller/Treasurer (1976-1978)

Mr. Majoros' responsibilities included financial management, general accounting and reporting, and income taxes.

Ernst & Ernst, *Auditor (1973-1976)*

Mr. Majoros was a member of the audit staff where his responsibilities included auditing, supervision, business systems analysis, report preparation, and corporate income taxes.

University of Baltimore - *(1971-1973)*

Mr. Majoros was a full-time student in the School of Business.

During this period Mr. Majoros worked consistently on a part-time basis in the following positions: Assistant Legislative Auditor – State of Maryland, Staff Accountant – Robert M. Carney & Co., CPA's, Staff Accountant – Naron & Wegad, CPA's, Credit Clerk – Montgomery Wards.

Central Savings Bank, *(1969-1971)*

Mr. Majoros was an Assistant Branch Manager at the time he left the bank to attend college as a full-time student. During his tenure at the bank, Mr. Majoros gained experience in each department of the bank. In addition, he attended night school at the University of Baltimore.

Education

University of Baltimore, School of Business, B.S. – Concentration in Accounting

Professional Affiliations

American Institute of Certified Public Accountants
Maryland Association of C.P.A.s
Society of Depreciation Professionals

Publications, Papers, and Panels

"Analysis of Staff Study on Comprehensive Tax Normalization," FERC Docket No. RM 80-42, 1980.

"Telephone Company Deferred Taxes and Investment Tax Credits – A Capital Loss for Ratepayers," Public Utility Fortnightly, September 27, 1984.

"The Use of Customer Discount Rates in Revenue Requirement Comparisons," Proceedings of the 25th Annual Iowa State Regulatory Conference, 1986

"The Regulatory Dilemma Created By Emerging Revenue Streams of Independent Telephone Companies," Proceedings of NARUC 101st Annual Convention and Regulatory Symposium, 1989.

"BOC Depreciation Issues in the States," National Association of State Utility Consumer Advocates, 1990 Mid-Year Meeting, 1990.

"Current Issues in Capital Recovery" 30th Annual Iowa State Regulatory Conference, 1991.

"Impaired Assets Under SFAS No. 121," National Association of State Utility consumer Advocates, 1996 Mid-Year Meeting, 1996.

"What's 'Sunk' Ain't Stranded: Why Excessive Utility Depreciation is Avoidable," with James Campbell, Public Utilities Fortnightly, April 1, 1999.

"Local Exchange Carrier Depreciation Reserve Percents," with Richard B. Lee, Journal of the Society of Depreciation Professionals, Volume 10, Number 1, 2000-2001

"Rolling Over Ratepayers," Public Utilities Fortnightly, Volume 143, Number 11, November, 2005.

Michael J. Majoros, Jr.

Date	Jurisdiction / Agency	Docket	Utility
		Federal Courts	
2005	US District Court, Northern District of AL, Northwestern Division 55/56/57/	CV 01-B-403-NW	Tennessee Valley Authority
		State Legislatures	
2006	Maryland General Assembly 61/	SB154	Maryland Healthy Air Act
2006	Maryland House of Delegates 62/	HB189	Maryland Healthy Air Act
		Federal Regulatory Agencies	
1979	FERC-US 19/	RP79-12	El Paso Natural Gas Co.
1980	FERC-US 19/	RM80-42	Generic Tax Normalization
1996	CRTC-Canada 30/	97-9	All Canadian Telecoms
1997	CRTC-Canada 31/	97-11	All Canadian Telecoms
1999	FCC 32/	98-137 (Ex Parte)	All LECs
1999	FCC 32/	98-91 (Ex Parte)	All LECs
1999	FCC 32/	98-177 (Ex Parte)	All LECs
1999	FCC 32/	98-45 (Ex Parte)	All LECs
2000	EPA 35/	CAA-00-6	Tennessee Valley Authority
2003	FERC 48/	RM02-7	All Utilities
2003	FCC 52/	03-173	All LECs
2003	FERC 53/	ER03-409-000, ER03-666-000	Pacific Gas and Electric Co.
		State Regulatory Agencies	
1982	Massachusetts 17/	DPU 557/558	Western Mass Elec. Co.
1982	Illinois 16/	ICC81-8115	Illinois Bell Telephone Co.
1983	Maryland 8/	7574-Direct	Baltimore Gas & Electric Co.
1983	Maryland 8/	7574-Surrebuttal	Baltimore Gas & Electric Co.
1983	Connecticut 15/	810911	Woodlake Water Co.
1983	New Jersey 1/	815-458	New Jersey Bell Tel. Co.
1983	New Jersey 14/	8011-827	Atlantic City Sewerage Co.
1984	Dist. Of Columbia 7/	785	Potomac Electric Power Co.
1984	Maryland 8/	7689	Washington Gas Light Co.
1984	Dist. Of Columbia 7/	798	C&P Tel. Co.
1984	Pennsylvania 13/	R-832316	Bell Telephone Co. of PA
1984	New Mexico 12/	1032	Mt. States Tel. & Telegraph
1984	Idaho 18/	U-1000-70	Mt. States Tel. & Telegraph
1984	Colorado 11/	1655	Mt. States Tel. & Telegraph

Michael J. Majoros, Jr.

1984	Dist. Of Columbia 7/	813	Potomac Electric Power Co.
1984	Pennsylvania 3/	R842621-R842625	Western Pa. Water Co.
1985	Maryland 8/	7743	Potomac Edison Co.
1985	New Jersey 1/	848-856	New Jersey Bell Tel. Co.
1985	Maryland 8/	7851	C&P Tel. Co.
1985	California 10/	I-85-03-78	Pacific Bell Telephone Co.
1985	Pennsylvania 3/	R-850174	Phila. Suburban Water Co.
1985	Pennsylvania 3/	R850178	Pennsylvania Gas & Water Co.
1985	Pennsylvania 3/	R-850299	General Tel. Co. of PA
1986	Maryland 8/	7899	Delmarva Power & Light Co.
1986	Maryland 8/	7754	Chesapeake Utilities Corp.
1986	Pennsylvania 3/	R-850268	York Water Co.
1986	Maryland 8/	7953	Southern Md. Electric Corp.
1986	Idaho 9/	U-1002-59	General Tel. Of the Northwest
1986	Maryland 8/	7973	Baltimore Gas & Electric Co.
1987	Pennsylvania 3/	R-860350	Dauphin Cons. Water Supply
1987	Pennsylvania 3/	C-860923	Bell Telephone Co. of PA
1987	Iowa 6/	DPU-86-2	Northwestern Bell Tel. Co.
1987	Dist. Of Columbia 7/	842	Washington Gas Light Co.
1988	Florida 4/	880069-TL	Southern Bell Telephone
1988	Iowa 6/	RPU-87-3	Iowa Public Service Company
1988	Iowa 6/	RPU-87-6	Northwestern Bell Tel. Co.
1988	Dist. Of Columbia 7/	869	Potomac Electric Power Co.
1989	Iowa 6/	RPU-88-6	Northwestern Bell Tel. Co.
1990	New Jersey 1/	1487-88	Morris City Transfer Station
1990	New Jersey 5/	WR 88-80967	Toms River Water Company
1990	Florida 4/	890256-TL	Southern Bell Company
1990	New Jersey 1/	ER89110912J	Jersey Central Power & Light
1990	New Jersey 1/	WR90050497J	Elizabethtown Water Co.
1991	Pennsylvania 3/	P900465	United Tel. Co. of Pa.
1991	West Virginia 2/	90-564-T-D	C&P Telephone Co.
1991	New Jersey 1/	90080792J	Hackensack Water Co.
1991	New Jersey 1/	WR90080884J	Middlesex Water Co.
1991	Pennsylvania 3/	R-911892	Phil. Suburban Water Co.
1991	Kansas 20/	176, 716-U	Kansas Power & Light Co.
1991	Indiana 29/	39017	Indiana Bell Telephone
1991	Nevada 21/	91-5054	Central Tele. Co. – Nevada
1992	New Jersey 1/	EE91081428	Public Service Electric & Gas
1992	Maryland 8/	8462	C&P Telephone Co.
1992	West Virginia 2/	91-1037-E-D	Appalachian Power Co.
1993	Maryland 8/	8464	Potomac Electric Power Co.
1993	South Carolina 22/	92-227-C	Southern Bell Telephone
1993	Maryland 8/	8485	Baltimore Gas & Electric Co.
1993	Georgia 23/	4451-U	Atlanta Gas Light Co.
1993	New Jersey 1/	GR93040114	New Jersey Natural Gas. Co.

Michael J. Majoros, Jr.

1994	Iowa 6/	RPU-93-9	U.S. West – Iowa
1994	Iowa 6/	RPU-94-3	Midwest Gas
1995	Delaware 24/	94-149	Wilm. Suburban Water Corp.
1995	Connecticut 25/	94-10-03	So. New England Telephone
1995	Connecticut 25/	95-03-01	So. New England Telephone
1995	Pennsylvania 3/	R-00953300	Citizens Utilities Company
1995	Georgia 23/	5503-0	Southern Bell
1996	Maryland 8/	8715	Bell Atlantic
1996	Arizona 26/	E-1032-95-417	Citizens Utilities Company
1996	New Hampshire 27/	DE 96-252	New England Telephone
1997	Iowa 6/	DPU-96-1	U S West – Iowa
1997	Ohio 28/	96-922-TP-UNC	Ameritech – Ohio
1997	Michigan 28/	U-11280	Ameritech – Michigan
1997	Michigan 28/	U-112 81	GTE North
1997	Wyoming 27/	7000-ztr-96-323	US West – Wyoming
1997	Iowa 6/	RPU-96-9	US West – Iowa
1997	Illinois 28/	96-0486-0569	Ameritech – Illinois
1997	Indiana 28/	40611	Ameritech – Indiana
1997	Indiana 27/	40734	GTE North
1997	Utah 27/	97-049-08	US West – Utah
1997	Georgia 28/	7061-U	BellSouth – Georgia
1997	Connecticut 25/	96-04-07	So. New England Telephone
1998	Florida 28/	960833-TP et. al.	BellSouth – Florida
1998	Illinois 27/	97-0355	GTE North/South
1998	Michigan 33/	U-11726	Detroit Edison
1999	Maryland 8/	8794	Baltimore Gas & Electric Co.
1999	Maryland 8/	8795	Delmarva Power & Light Co.
1999	Maryland 8/	8797	Potomac Edison Company
1999	West Virginia 2/	98-0452-E-GI	Electric Restructuring
1999	Delaware 24/	98-98	United Water Company
1999	Pennsylvania 3/	R-00994638	Pennsylvania American Water
1999	West Virginia 2/	98-0985-W-D	West Virginia American Water
1999	Michigan 33/	U-11495	Detroit Edison
2000	Delaware 24/	99-466	Tidewater Utilities
2000	New Mexico 34/	3008	US WEST Communications, Inc.
2000	Florida 28/	990649-TP	BellSouth -Florida
2000	New Jersey 1/	WR30174	Consumer New Jersey Water
2000	Pennsylvania 3/	R-00994868	Philadelphia Suburban Water
2000	Pennsylvania 3/	R-0005212	Pennsylvania American Sewerage
2000	Connecticut 25/	00-07-17	Southern New England Telephone
2001	Kentucky 36/	2000-373	Jackson Energy Cooperative
2001	Kansas 38/39/40/	01-WSRE-436-RTS	Western Resources
2001	South Carolina 22/	2001-93-E	Carolina Power & Light Co.
2001	North Dakota 37/	PU-400-00-521	Northern States Power/Xcel Energy
2001	Indiana 29/41/	41746	Northern Indiana Power Company

Michael J. Majoros, Jr.

2001	New Jersey 1/	GR01050328	Public Service Electric and Gas
2001	Pennsylvania 3/	R-00016236	York Water Company
2001	Pennsylvania 3/	R-00016339	Pennsylvania America Water
2001	Pennsylvania 3/	R-00016356	Wellsboro Electric Coop.
2001	Florida 4/	010949-EL	Gulf Power Company
2001	Hawaii 42/	00-309	The Gas Company
2002	Pennsylvania 3/	R-00016750	Philadelphia Suburban
2002	Nevada 43/	01-10001 &10002	Nevada Power Company
2002	Kentucky 36/	2001-244	Fleming Mason Electric Coop.
2002	Nevada 43/	01-11031	Sierra Pacific Power Company
2002	Georgia 27/	14361-U	BellSouth-Georgia
2002	Alaska 44/	U-01-34,82-87,66	Alaska Communications Systems
2002	Wisconsin 45/	2055-TR-102	CenturyTel
2002	Wisconsin 45/	5846-TR-102	TelUSA
2002	Vermont 46/	6596	Citizen's Energy Services
2002	North Dakota 37/	PU-399-02-183	Montana Dakota Utilities
2002	Kansas 40/	02-MDWG-922-RTS	Midwest Energy
2002	Kentucky 36/	2002-00145	Columbia Gas
2002	Oklahoma 47/	200200166	Reliant Energy ARKLA
2002	New Jersey 1/	GR02040245	Elizabethtown Gas Company
2003	New Jersey 1/	ER02050303	Public Service Electric and Gas Co.
2003	Hawaii 42/	01-0255	Young Brothers Tug & Barge
2003	New Jersey 1/	ER02080506	Jersey Central Power & Light
2003	New Jersey 1/	ER02100724	Rockland Electric Co.
2003	Pennsylvania 3/	R-00027975	The York Water Co.
2003	Pennsylvania /3	R-00038304	Pennsylvania-American Water Co.
2003	Kansas 20/ 40/	03-KGSG-602-RTS	Kansas Gas Service
2003	Nova Scotia, CN 49/	EMO NSPI	Nova Scotia Power, Inc.
2003	Kentucky 36/	2003-00252	Union Light Heat & Power
2003	Alaska 44/	U-96-89	ACS Communications, Inc.
2003	Indiana 29/	42359	PSI Energy, Inc.
2003	Kansas 20/ 40/	03-ATMG-1036-RTS	Atmos Energy
2003	Florida 50/	030001-E1	Tampa Electric Company
2003	Maryland 51/	8960	Washington Gas Light
2003	Hawaii 42/	02-0391	Hawaiian Electric Company
2003	Illinois 28/	02-0864	SBC Illinois
2003	Indiana 28/	42393	SBC Indiana
2004	New Jersey 1/	ER03020110	Atlantic City Electric Co.
2004	Arizona 26/	E-01345A-03-0437	Arizona Public Service Company
2004	Michigan 27/	U-13531	SBC Michigan
2004	New Jersey 1/	GR03080683	South Jersey Gas Company
2004	Kentucky 36/	2003-00434,00433	Kentucky Utilities, Louisville Gas & Electric
2004	Florida 50/ 54/	031033-EI	Tampa Electric Company
2004	Kentucky 36/	2004-00067	Delta Natural Gas Company

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2004	Georgia 23/	18300, 15392, 15393	Georgia Power Company
2004	Vermont 46/	6946, 6988	Central Vermont Public Service Corporation
2004	Delaware 24/	04-288	Delaware Electric Cooperative
2004	Missouri 58/	ER-2004-0570	Empire District Electric Company
2005	Florida 50/	041272-EI	Progress Energy Florida, Inc.
2005	Florida 50/	041291-EI	Florida Power & Light Company
2005	California 59/	A.04-12-014	Southern California Edison Co.
2005	Kentucky 36/	2005-00042	Union Light Heat & Power
2005	Florida 50/	050045 & 050188-EI	Florida Power & Light Co.
2005	Kansas 38/ 40/	05-WSEE-981-RTS	Westar Energy, Inc.
2006	Delaware 24/	05-304	Delmarva Power & Light Company
2006	California 59/	A.05-12-002	Pacific Gas & Electric Co.
2006	New Jersey 1/	GR05100845	Public Service Electric and Gas Co.
2006	Colorado 60/	06S-234EG	Public Service Co. of Colorado
2006	Kentucky 36/	2006-00172	Union Light, Heat & Power
2006	Kansas 40/	06-KGSG-1209-RTS	Kansas Gas Service
2006	West Virginia 2/	06-0960-E-42T, 06-1426-E-D	Allegheny Power
2006	West Virginia 2/	05-1120-G-30C, 06-0441-G-PC, et al.	Hope Gas, Inc. and Equitable Resources, Inc.
2007	Delaware 24/	06-284	Delmarva Power & Light Company
2007	Kentucky 36/	2006-00464	Atmos Energy Corporation
2007	Colorado 60/	06S-656G	Public Service Co. of Colorado
2007	California 59/	A.06-12-009, A.06-12-010	San Diego Gas & Electric Co., and Southern California Gas Co.
2007	Kentucky 36/	2007-00143	Kentucky-American Water Co.
2007	Kentucky 36/	2007-00089	Delta Natural Gas Co.
2008	Kansas 40/	08-ATMG-280-RTS	Atmos Energy Corporation
2008	New Jersey 1/	GR07110889	New Jersey Natural Gas Co.
2008	North Dakota 37/	PU-07-776	Northern States Power/Xcel Energy

Michael J. Majoros, Jr.

PARTICIPATION AS NEGOTIATOR IN FCC TELEPHONE DEPRECIATION RATE REPRESCRIPTION CONFERENCES

COMPANY	YEARS	CLIENT
Diamond State Telephone Co. 24/	1985 + 1988	Delaware Public Service Comm
Bell Telephone of Pennsylvania 3/	1986 + 1989	PA Consumer Advocate
Chesapeake & Potomac Telephone Co. - Md. 8/	1986	Maryland People's Counsel
Southwestern Bell Telephone – Kansas 20/	1986	Kansas Corp. Commission
Southern Bell – Florida 4/	1986	Florida Consumer Advocate
Chesapeake & Potomac Telephone Co.-W.Va. 2/	1987 + 1990	West VA Consumer Advocate
New Jersey Bell Telephone Co. 1/	1985 + 1988	New Jersey Rate Counsel
Southern Bell - South Carolina 22/	1986 + 1989 + 1992	S. Carolina Consumer Advocate
GTE-North – Pennsylvania 3/	1989	PA Consumer Advocate

Michael J. Majoros, Jr.

PARTICIPATION IN PROCEEDINGS WHICH WERE SETTLED BEFORE TESTIMONY WAS SUBMITTED

STATE	DOCKET NO.	UTILITY
Maryland 8/	7878	Potomac Edison
Nevada 21/	88-728	Southwest Gas
New Jersey 1/	WR90090950J	New Jersey American Water
New Jersey 1/	WR900050497J	Elizabethtown Water
New Jersey 1/	WR91091483	Garden State Water
West Virginia 2/	91-1037-E	Appalachian Power Co.
Nevada 21/	92-7002	Central Telephone - Nevada
Pennsylvania 3/	R-00932873	Blue Mountain Water
West Virginia 2/	93-1165-E-D	Potomac Edison
West Virginia 2/	94-0013-E-D	Monongahela Power
New Jersey 1/	WR94030059	New Jersey American Water
New Jersey 1/	WR95080346	Elizabethtown Water
New Jersey 1/	WR95050219	Toms River Water Co.
Maryland 8/	8796	Potomac Electric Power Co.
South Carolina 22/	1999-077-E	Carolina Power & Light Co.
South Carolina 22/	1999-072-E	Carolina Power & Light Co.
Kentucky 36/	2001-104 & 141	Kentucky Utilities, Louisville Gas and Electric
Kentucky 36/	2002-485	Jackson Purchase Energy Corporation

Michael J. Majoros, Jr.

Clients

1/ New Jersey Rate Counsel/Advocate	33/ Michigan Attorney General
2/ West Virginia Consumer Advocate	34/ New Mexico Attorney General
3/ Pennsylvania OCA	35/ Environmental Protection Agency Enforcement Staff
4/ Florida Office of Public Advocate	36/ Kentucky Attorney General
5/ Toms River Fire Commissioner's	37/ North Dakota Public Service Commission
6/ Iowa Office of Consumer Advocate	38/ Kansas Industrial Group
7/ D.C. People's Counsel	39/ City of Witchita
8/ Maryland's People's Counsel	40/ Kansas Citizens' Utility Rate Board
9/ Idaho Public Service Commission	41/ NIPSCO Industrial Group
10/ Western Burglar and Fire Alarm	42/ Hawaii Division of Consumer Advocacy
11/ U.S. Dept. of Defense	43/ Nevada Bureau of Consumer Protection
12/ N.M. State Corporation Comm.	44/ GCI
13/ City of Philadelphia	45/ Wisc. Citizens' Utility Rate Board
14/ Resorts International	46/ Vermont Department of Public Service
15/ Woodlake Condominium Association	47/ Oklahoma Corporation Commission
16/ Illinois Attorney General	48/ National Assn. of State Utility Consumer Advocates
17/ Mass Coalition of Municipalities	49/ Nova Scotia Utility and Review Board
18/ U.S. Department of Energy	50/ Florida Office of Public Counsel
19/ Arizona Electric Power Corp.	51/ Maryland Public Service Commission
20/ Kansas Corporation Commission	52/ MCI
21/ Public Service Comm. – Nevada	53/ Transmission Agency of Northern California
22/ SC Dept. of Consumer Affairs	54/ Florida Industrial Power Users Group
23/ Georgia Public Service Comm.	55/ Sierra Club
24/ Delaware Public Service Comm.	56/ Our Children's Earth Foundation
25/ Conn. Ofc. Of Consumer Counsel	57/ National Parks Conservation Association, Inc.
26/ Arizona Corp. Commission	58/ Missouri Office of the Public Counsel
27/ AT&T	59/ The Utility Reform Network
28/ AT&T/MCI	60/ Colorado Office of Consumer Counsel
29/ IN Office of Utility Consumer Counselor	61/ MD State Senator Paul G. Pinsky
30/ Unitel (AT&T – Canada)	62/ MD Speaker of the House Michael Busch
31/ Public Interest Advocacy Centre	
32/ U.S. General Services Administration	

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF KENTUCKY UTILITIES COMPANY, INC. FOR AN ADJUSTMENT OF BASE RATES	)))	Case No. 2008-00251 C/W Case No. 2007-00565

AFFIDAVIT OF MICHAEL MAJOROS

District of Columbia)
)
)

Michael Majoros, being first duly sworn, states the following: The prepared Pre-Filed Direct Testimony, and the Schedules and Appendix attached thereto constitute the direct testimony of Affiant in the above-styled case. Affiant states that he would give the answers set forth in the Pre-Filed Direct Testimony if asked the questions propounded therein. Affiant further states that, to the best of his knowledge, his statements made are true and correct. Further affiant saith not.

Michael Majoros

SUBSCRIBED AND SWORN to before me this 20th day of October, 2008.

Angel R. Fink

NOTARY PUBLIC

My Commission Expires: March 14, 2010

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

APPLICATION OF KENTUCKY	)	
UTILITIES COMPANY FOR AN	)	**CASE NO. 2008-00251**
ADJUSTMENT OF BASE RATES	)	

PREPARED DIRECT TESTIMONY AND SCHEDULES

OF

GLENN A. WATKINS

ON BEHALF OF THE

KENTUCKY OFFICE OF THE ATTORNEY GENERAL

OCTOBER 30, 2008

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Glenn A. Watkins. My business address is James Center III, 1051 East Cary Street, Suite 601, Richmond, VA 23219.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am a Principal and Senior Economist with Technical Associates, Inc., which is an economic and financial consulting firm with offices in Richmond, Virginia.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am testifying on behalf of the Office of Rate Intervention of the Kentucky Office of Attorney General ("OAG").

Q. PLEASE DESCRIBE YOUR PROFESSIONAL QUALIFICATIONS.

A. Except for a six-month period during 1987 in which I was employed by Old Dominion Electric Cooperative as its forecasting and rate economist, I have been employed by Technical Associates continuously since 1980.

During my career at Technical Associates, I have conducted marginal and embedded cost of service, rate design, cost of capital, and load forecasting studies involving numerous electric, gas, water/wastewater, and telephone utilities, and have provided expert testimony in Alabama, Arizona, Georgia, Kentucky, Maine, Maryland, Massachusetts, Michigan, New Jersey, Ohio, Illinois, Pennsylvania, Vermont, Virginia, South Carolina, Washington, and West Virginia. I hold an M.B.A. and B.S. in economics from Virginia Commonwealth University. I am a member of several professional organizations as well as a Certified Rate of Return Analyst. A more complete description of my education and experience is provided in my Schedule GAW_1 to my testimony.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. Technical Associates has been retained by the OAG to evaluate the reasonableness of Kentucky Utilities Company's ("KU" or "Company") proposed electric weather normalization adjustment, electric and gas class cost of service studies

(CCOSS), proposed distribution of revenues by class, and residential electric and gas rate designs. The purpose of my testimony, therefore, is to comment on KU's proposals on these issues and to present my findings and recommendations based on the results of the studies I have undertaken on behalf of the OAG.

ELECTRIC WEATHER NORMALIZATION

Q. HAVE YOU EXAMINED KU'S PROPOSED ELECTRIC WEATHER NORMALIZATION ADJUSTMENT IN THIS CASE?

A. Yes.

Q. WHAT IS THE NET EFFECT OF THE COMPANY'S PROPOSED WEATHER NORMALIZATION ADJUSTMENT?

A. KU witness William Seelye sponsors a weather normalization adjustment that will impact customers' ultimate rates in two respects: the first is the overall revenue requirement effect and the second is a rate design effect. In terms of the overall revenue requirement effect, Mr. Seelye adjusts actual test year revenues and variable expenses downward to correct for what he considers to be unusual (or abnormal) weather occurring during the test year. In other words, the Company does not expect to achieve the same level of kWh sales (and revenue) that was experienced during the test year on a going forward basis. Mr. Seelye's weather normalization adjustment results in reduction to actual test year revenues of $8.721 million and a reduction in variable expenses of $4.355 million. This downward adjustment to actual net revenues has an upward impact on the Company's revenue requirement on a going forward basis; i.e., all other things constant, this adjustment increases the revenue requirement. The second aspect of this weather normalization adjustment is the rate design effect. Because the weather adjustment reduces test year kWh sales, there are fewer units (kWh) to collect the overall revenue requirement such that there is an additional upward pressure on customers resulting from the weather normalization adjustment.

Q. MR. WATKINS, WHAT IS THE BASIS FOR KU'S REQUEST TO ADJUST ITS ACTUAL TEST YEAR SALES VOLUMES AND REVENUES?

A. As a result of abnormal weather, the Company claims that actual test year sales volumes (kWh) were greater than can be expected on a going forward basis.

Q. DO YOU AGREE THAT THE COMPANY'S PROPOSED ELECTRIC WEATHER NORMALIZATION ADJUSTMENT SHOULD BE USED FOR RATEMAKING PURPOSES?

A. From a conceptual standpoint, the general consensus of public utility commissions throughout the United States is that it is unreasonable to weather normalize electric utility revenues for ratemaking purposes. In this regard, this Commission would be well advised to continue its current practice of not considering electric weather normalization which is consistent with the vast majority of other states. This would translate to a disallowance of $4.366 million from the company's request in net revenue ($8.721 million in revenue less $4.355 million in variable expense).

Q. DO CUSTOMERS KWH ENERGY USAGES VARY MATERIALLY WITH CHANGES IN WEATHER CONDITIONS?

A. Yes for some customers, and no for other customers. As a result of variances in electrical appliance and equipment saturations, some customers' electric usage varies significantly with changes in weather (temperature) while other customers' energy usage vary much less. For example, on an extremely hot summer day, residential customers will generally use considerably more electricity than on a mild, spring like day due to air conditioning load. On the other hand, the total electricity used by an industrial customer may not be materially different on the hot verses mild days due to this customer's non-weather sensitive load over shadowing its space cooling requirements (at least in terms of ambient outdoor temperatures).

Q. OVER THE COURSE OF AN ENTIRE YEAR, DO PERIODS OF MILD WEATHER OFFSET PERIODS OF EXTREME WEATHER IN TERMS OF ELECTRICITY USAGE?

A. In general, yes. This is particularly true for electricity sales.

Q. PLEASE EXPLAIN.

A. Although the following is common knowledge, it is important to consider how electricity is used and how weather affects this usage. For purposes of my explanation, I will focus on residential customers. As indicated earlier, there is no doubt that weather, primarily temperature, effects energy usage. In the summer there are periods of days that are very hot and electricity sales are elevated. Similarly there are mild days throughout the summer in which electricity sales are depressed due to reduced air conditioner loads. These hot and mild periods occur virtually every year. The question then arises if a particular cooling season (summer) as a whole is abnormally warm with an attendant abnormally high level of energy sales. In addition to cooling load (air conditions), electricity is also used for space heating by many customers in the winter. Similar to severe and mild weather in the summer, electricity sales on a daily basis are affected in the winter due to electric heating requirements. In addition to weather sensitive appliances, residential customers use a significant amount of electricity for other appliances that do not vary with weather; e.g., refrigerators/freezers, televisions, etc. Because of these factors and situations, annual electricity sales tend to be much more stable than say, natural gas sales, which are predominated by space heating load requirements in the winter. For these reasons, it is rare for commissions to consider weather normalization for electric utilities. In this regard, and as a matter of policy, the Commission would be well guided to continue its practice of not considering weather normalization for Kentucky electric utilities.

Q. WE KNOW THAT RESIDENTIAL KWH SALES VARY DUE TO WEATHER CONDITIONS ON A DAY-TO-DAY BASIS BUT HOW DOES ONE DETERMINE IF WEATHER IS ABNORMAL OVER THE COURSE OF A SEASON?

A. There is no definitive answer to this question. There is no doubt that a summer day in the high 90's is a hot day and warmer than "average". However, the question that must be answered is whether the summer overall was "abnormal". Similarly, one must determine if a winter season is materially different than normal; i.e., extremely severe or mild. With regard to seasonal variations from year to year, there is significant debate as to what constitutes departure from what is reasonably normal or expected. The National Oceanic and Atmospheric Administration ("NOAA"), National Climatic Data Center defines normal weather as a thirty-year average for the most recent completed three decades. In other words, the current NOAA definition of normal weather is for the period 1971 through 2000. Because of short-term trends in seasonal weather patters, shorter periods are sometimes used to define normal weather as well as using the most recent thirty years to define normal. I am also aware of instances in which much longer periods are used to define normal weather for a season.

Even with these differences in defining "normal" weather, one cannot say that the weather was particularly extreme simply because there is somewhat of a deviation from a historical average. In other words, assume the average maximum temperature for a given summer day is 85 degrees. If the actual temperature is 87 degrees, I do not believe it can be said that this is "abnormal" or "extreme" for that day. In this regard, the determination of "abnormal" or "extreme" is truly subjective.

Q. EVEN THOUGH THE DEFINITION OF ABNORMAL WEATHER IS SUBJECTIVE, ARE THERE METHODS THAT CAN BE USED TO FAIRLY AND REASONABLY DEFINE NORMAL AND ABNORMAL WEATHER?

A. Yes.

Q. PLEASE EXPLAIN.

A. Remembering that we should be concerned about the overall variation in weather over an entire season (hearting or cooling), a banding approach is, in my opinion, a fair and reasonable way to determine if a season's weather falls inside or outside of a band of reasonably normal weather. This banding approach is used by Mr. Seelye in this case. To the extent the Commission authorizes a weather normalization adjustment in this case, I could support the concept of banding, as it eliminates quibbling over minor variances from a pre-determined average or "normal" weather pattern.

Q. PLEASE EXPLAIN THIS BANDING APPROACH IN LAYMAN'S TERMS.

A. The traditional unit to measure summer temperatures over time is cooling degree days ("CDD") and the traditional unit to measure winter temperatures over time is Heating Degree Days ("HDD").[1] Assume that "normal" or average CDD's over the entire cooling season are 1,000. As discussed earlier, if the actual CDD were say 1010, we likely would not consider this an abnormally warm summer. However, if we subjectively determine a relative percentage of time in which we deem weather as abnormal, we can apply a simple statistical technique to determine the bands of normalcy. If we assume the variations in weather from year to year are random (no trend or pattern) we can subjectively define a percentage of time (years) in which weather is considered normal. For example, suppose we decide (subjectively) that weather occurring 75% of the time within a long term average is normal and the remaining 25% of the time the weather is defined as abnormal (12.5% mild and 12.5% severe), we can quantify the bands of normal weather. Consider the following hypothetical example:

<u>Seasonal Cooling Degree Days</u>

```
                    900            1,000            1,100
←-------------------|----------------|----------------|------------------→
Abnormal →          |            ←Normal→             | ← Abnormal
```

If we know that 75% of the time a season's CDD fall between 900 and 1,100 we would define this range as normal. If a season's actual CDD's are greater than 1,100 we would deem that season as abnormally warm. Similarly, if the actual CDD's in a season are less than 900 we would deem that season abnormally mild. This is the approach proposed by Mr. Seelye. As indicated earlier, I support this approach but it must be emphasized that the range of normalcy is subjective and should be determined by the Commission. It should also be noted that this approach requires the assumption that annual seasonal weather variations are truly random; i.e., no trends or patterns are present.

Q. IN YOUR HYPOTHETICAL EXAMPLE, YOU USED A NORMALCY BAND OF 75%. WHAT BAND IS USED BY MR. SEELYE?

A. Approximately sixty-eight percent.

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[1] CDD is traditionally defined as 65 degrees minus the average temperature (High and Low) for a day. HDD is traditionally defined as average temperature minus 65 degrees. CDD and HDD cannot be negative.

Q. HOW DID MR. SEELYE SELECT SIXTY-EIGHT PERCENT AS HIS NORMAL BAND FOR WEATHER?

A. This 68% is a convenient percentage in statistics in that it represents the percentage of time that one can expect weather to vary within plus or minus one standard deviation. There is nothing especially significant about a standard deviation of 1.0, as the exact same statistical techniques can be used at any level selected for normalcy; e.g., 50%, 75%, etc.

Q. WHAT WEATHER PATTERNS WERE ACTUALLY EXPERIENCED IN THE KU SERVICE AREA DURING THE TEST YEAR?

A. Overall, the cooling season (summer period) was exceptionally warm during the test year, whereas the heating season (winter period) was somewhat milder than average. The following is a comparison of monthly CDD and HDD to the most recent 30-year average for CDD and HDD:

Month	CDD or HDD Actual Test Year	30-Year Average	Difference
Cooling Season (CDD)			
June	284	242	42
July	309	361	<52>
August	496	332	164
September	238	151	87
Total	1,327	1,085	242
Heating Season (HDD)			
November	577	555	22
December	765	883	<118>
January	1,012	989	23
February	849	801	48
March	638	609	29
Total	3,841	3,837	4

As can be seen above, August and September 2007 were exceptionally warmer than the 30-year average, while December 2007 was considerably milder than the 30-year average.

Q. **WHY ARE APRIL, MAY AND OCTOBER NOT PROVIDED IN THE TABLE ABOVE?**

A. These months are considered shoulder months. Days in April and May can be cool or fairly warm such that these months are comprised of heating degree days and cooling degree days. As such, heating and air conditioning loads are usually not predictable in April and May. The same is true for October. Generally, the early part of October is warm and air conditioning load is still present. By the middle to end of October, the weather cools to the point that there is some heating load. As such, October is not very consistent as far as what can be considered "normal" weather.

Q. **MR. WATKINS, IT IS GENERALLY FAIRLY COOL IN APRIL AND FAIRLY WARM BY THE END OF MAY IN KENTUCKY. WOULD IT BE APPROPRIATE TO CONSIDER EACH APRIL AS PART OF THE HEATING SEASON AND LATE MAY AS PART OF THE COOLING SEASON?**

A. In my opinion no. Both of these months experience considerable variation between periods cold enough for space heating, mild enough for open windows, and warm enough for air conditioning load.

Q. **FOR PURPOSES OF WEATHER NORMALIZATIONS, HOW DO YOU DEFINE KU'S COOLING AND HEATING SEASONS?**

A. I define KU's cooling season as the months of June through September and the heating season as the months of November through March.

Q. **IF THE COMMISSION ACCEPTS A BANDING APPROACH AS PROPOSED BY MR. SEELYE AND SUPPORTED BY YOU, HOW SHOULD THIS APPROACH BE APPLIED TO THE HEATING AND COOLING SEASONS?**

A. The banding should be applied separately to the entire heating season and again separately for the entire cooling season. This is a major difference in the manner in which Mr. Seelye applied his weather banding, in that Mr. Seelye applies a weather normalcy band to each individual month. Mr. Seelye's monthly banding results in a bias to the annual normalized sales volumes.

Q. PLEASE EXPLAIN.

A. As discussed earlier, a given heating or cooling season is comprised of days in which it is milder than expected and more severe than expected. The overall objective is to consider the overall effects of weather during a heating or cooling season and Mr. Seelye's monthly banding does not meet this objective. To illustrate, consider the actual experience of July and August during the test year. July's actual CDDs were 309 which compare to a 30-year average July CDD of 361. This is a difference of -52 CDD which indicates that July was somewhat milder than the long-term average. Because this deviation from average (-52) does not fall outside of Mr. Seelye's monthly band, it is not adjusted and this mild weather for July is not considered any further in his analysis.

However, August was adjusted by Mr. Seelye because this individual month's weather fell outside of his monthly band. The actual CDDs for August in the test year were 496. This compares with a long-term average of 332 for August and is a difference of 164 CDDs. This exceptionally hot weather during August 2007 falls outside of Mr. Seelye's normalcy band and August's kWh sales were adjusted downward. However, no adjustment or consideration was given to the somewhat milder weather experienced during July 2007.

Q. HOW HAVE YOU ESTIMATED THE EFFECTS OF WEATHER ON CUSTOMER'S ELECTRICITY USAGE?

A. As discussed earlier, variations in electricity sales during the summer are affected by variations in air conditioning load, while winter kWh sales variations are affected by changes in space heating load. The two uses cannot be measured together and must be examined separately. Therefore, I have conducted separate analyses for the cooling (summer) and heating (winter) seasons.

I conducted linear regression analyses by season for each rate class in order to develop a weather sensitive usage coefficient for each class. In other words, the weather sensitive coefficient measures the incremental level at which a classes kWh usage varies with an incremental change in weather (CDD in summer, HDD in winter). Specifically, I developed a separate regression model for each class and each season (cooling and heating). These regression models were developed based on daily kWh usage and daily degree days. In other words, the cooling season is comprised of four months (June through September). My model was developed using each daily observation during this season (142 days). Because usage patterns can and do vary significantly between weekdays and weekends/holidays, I have also reflected this reality in my analysis of daily observations. With regard to the Residential class, I have expressed daily kWh usage on a per customer basis in order to prevent any skewness in my regression models. The Commercial and Industrial classes were analyzed on a total class basis.

Q. WHAT ARE YOUR CONCLUSIONS REGARDING WEATHER NORMALIZATION FOR KU'S ELECTRIC OPERATIONS DURING THE TEST YEAR?

A. Based on my analyses, I conclude that the overall cooling season (summer) during the test year was exceptionally warm which translated into exceptionally high summer energy sales for KU. This weather (and attendant kWh sales) falls beyond what can reasonably be expected on a going-forward basis and warrants a downward adjustment. Although the test year's heating season was somewhat milder than normal, these sales do not warrant adjustment.

Q. IS THERE ANY BIAS IN YOUR CONCLUSION THAT SUMMER KWH SALES SHOULD BE ADJUSTED DOWNWARD DUE TO EXCEPTIONALLY SEVERE WEATHER, BUT WINTER KWH SALES DO NOT WARRANT AN OPPOSITE UPWARD ADJUSTMENT DUE TO A SOMEWHAT MILDER WINTER?

A. As long as a banding approach is used, the answer is no. This is because the summer normalization is made only to the outer limit of the "normalcy" band and not all the way to an average historical experience. Thus, while it is true that the milder winter sales somewhat offset the extreme weather-related summer sales, each season reflects a reasonable level of what can be expected on a going-forward basis.

Q. WHAT ARE THE RESULTS OF YOUR WEATHER NORMALIZATION ANALYSIS FOR KU'S ELECTRIC OPERATIONS?

A. My Schedule GAW_2 presents the results of my weather normalization analysis for KU's electric operations. Page 1 of this Schedule provides a summary of each class' kWh and revenue adjustment as well as the adjustment required to variable expenses. Pages 2 through 12 present the detailed kWh adjustment for each class. My weather normalization analysis results in a reduction to actual test year revenues of $2.603 million and a reduction to actual test year expenses of $1.320 million.

Q. YOU HAVE ALREADY DISCUSSED YOUR DISAGREEMENT WITH MR. SEELYE REGARDING MONTHLY VERSUS SEASONAL ANALYSIS AND ADJUSTMENTS. DO YOU HAVE ANY OTHER DISAGREEMENTS WITH MR. SEELYE'S PROPOSED WEATHER NORMALIZATION ANALYSES?

A. Yes.

Q. PLEASE EXPLAIN THESE OTHER DISAGREEMENTS.

A. I disagree with Mr. Seelye's decision to use the step-wise multiple regression technique as well as his inclusion of numerous weather-related variables. At the outset I want it to be clear that I understand and appreciate Mr. Seelye's desire to conduct his statistical analysis on an objective basis. However, Mr. Seelye's procedures are not warranted and often produce conflicting model results.

We have already established that weather generally affects electricity sales. On an hourly or daily basis, these weather factors can include ambient temperature, wind velocity, relative humidity, the degree of cloud cover, whether snow cover is present to insulate structures, whether a thunderstorm appears on a hot afternoon and dramatically and suddenly reduces load (and sales), wind direction, and perhaps a few more factors.

Mr. Seelye has attempted to consider many of these short-term factors in his modeling analysis by using a technique known as step-wise regression. This statistical technique selects a combination of possible variables to be considered and selects an equation that maximizes certain statistic parameters. This step-wise technique is simply a mathematical algorithm calculated by a computer. In other words, the variables offered to a computer in the step-wise technique are simply sets of numbers. Obviously, the computer has no ability to determine if the potential variables are consistent with the task at hand or even if they make sense from a conceptual perspective. There is no doubt that variables selected using the step-wise technique are objective. However, this technique is no substitute for informed human judgment. In their much respected text book, Applied Regression Analysis, Norman Draper and Harry Smith render the following opinion regarding the step-wise procedure used for econometric regression analyses:

> ***Opinion.*** We believe this to be one of the best of the variable selection procedures and recommend its use. It makes economical use of computer facilities, and it avoids working with more X's than are necessary while improving the equation at every stage. However, stepwise regression can easily be abused by the "amateur" statistician. As with all the procedures discussed, sensible judgment is still required in the initial selection of variables and in the critical examination of the model through examination of residuals. It is easy to rely too heavily on the automatic selection performed in the computer. [Third Edition, page 338]

As a result of Mr. Seelye's attempt to be unnecessarily surgically precise, he arrives at nonsensical conclusions and models. As an illustration, remember that Mr. Seelye developed a separate regression equation, by class, for each month. Consider and compare Mr. Seelye's step-wise derived Residential models for July and August.

Variable	July 1/	August 1/
Intercept	-2,394,075	8,474,433
Maximum Temperature	129,398	--
CDD70	212,068	391,299
Weekend	453,879	1,055,056

1/ Per Seelye Exhibit 11.

Mr. Seelye's step-wise procedures result in a finding that in July, kWh sales are a function (related to) of maximum temperature, cooling degree days (CDD70), and weekday versus weekends. However, in August, the computer determined that Residential kWh sales are not a function of this same set of explanatory variables, but rather, only cooling degree days (CDD70) and weekdays versus weekends. Related to the inconsistency of these adjoining summer months is the level in which kWh usage varies with changes in overall average daily temperatures (CDD70). Notice that the July model has a CDD70 coefficient of 212,068, while the August coefficient of 391,299.

What this means is that, all other things constant, kWh sales will vary by 212,068 kWh for each variation in CDD70 during July, but will vary by 391,299 in August.

There are many more inconsistencies and seemingly non-sensical results for other months as well as across classes, that I will not dwell on. In my opinion, and that of the industry, HDD and CDD are the accepted and most appropriate explanatory variables.

ELECTRIC CLASS COST OF SERVICE

Q. PLEASE EXPLAIN THE CONCEPT OF A CLASS COST OF SERVICE STUDY ("CCOSS").

A. First, I note that there are two general types of cost of service studies used for public utility ratemaking: marginal cost studies; and embedded, fully allocated cost studies. KU has utilized a traditional embedded cost of service concept in this case for purposes of establishing its overall retail revenue requirement, as well as for its class cost of service study ("CCOSS"). As such, I will limit my explanation to embedded class cost of service studies.

Embedded cost of service studies are often referred to as fully allocated cost studies. This is because the vast majority of an electric utility's plant investment serves all customers, and the majority of expenses are incurred in a joint manner such that these costs cannot be specifically attributed to any individual customer or group of customers. To the extent that certain costs can be specifically attributable to a particular customer (or group of customers), these costs are often directly assigned in a CCOSS. However, the vast majority of KU's Production, Transmission, and Distribution plant and expenses are incurred jointly to serve all (or most) customers. These joint costs are then allocated to rate classes. It is generally recognized that to the extent possible, joint costs should be allocated to classes based on the concept of cost causation; i.e., costs are allocated based on specific factors that cause costs to be incurred by the utility. Although cost analysts generally strive to abide by the concept of cost causation to the greatest extent practical, some costs (particularly overhead costs), cannot be attributed to specific exogenous factors and must be subjectively assigned or allocated to rate classes. With regards to those costs in which cost causation can be attributed, cost of service experts often disagree as to what is the most cost causative factor; e.g., peak demand, energy usage, number of customers, etc.

Q. PLEASE EXPLAIN HOW CCOSS RESULTS SHOULD BE USED IN THE RATEMAKING PROCESS.

A. Although there are certain principles used by all cost of service analysts, there are often significant disagreements on the specific factors that drive certain costs. These disagreements can and do arise as a result of the quality of data and level of detail available from financial records, as well as fundamental differences in opinions regarding the design or cost causation factors that should be considered to properly allocate costs to rate schedules or customer classes. Furthermore, and as mentioned earlier, cost causation factors cannot be realistically ascribed to some costs such that subjective decisions are required.

In this regard, two different cost studies conducted for the same utility and time period can, and often do, yield different results. As such, regulators should consider CCOSS results as one of many tools in assigning revenue responsibility.

Q. PLEASE EXPLAIN HOW YOU PROCEEDED WITH YOUR ANALYSIS OF KU'S CCOSS.

A. The process in which I conducted my analysis in this case was identical to how I evaluate all CCOSSs. First, I reviewed the structure and organization of the Company's CCOSS. Once the basic structure was understood, I reviewed the accuracy and completeness of the primary drivers (allocators) used to assign costs to rate schedules and classes. Next, I reviewed KU's selection of allocators to specific rate base, revenue and expense accounts. Finally, I adjusted certain aspects of the Company's study to better reflect cost causation and cost incidence by rate schedule and customer class.

Q. DID YOU FIND THE COMPANY'S STUDY TO BE MATHEMATICALLY ACCURATE?

A. Yes. Perhaps the most fundamental requirement of an embedded CCOSS is that the sum of the parts (classes) must equal the whole (system). This is true with respect to the allocation of financial accounts, as well as the various allocation factors. Furthermore, certain costs previously allocated are carried forward for other purposes such as for the development of composite or internal allocators and for the assignment of income taxes. In all regards, I found Mr. Seelye's CCOSS to be mathematically accurate.

Q. DID YOUR EXAMINATION RESULT IN ANY DISAGREEMENTS WITH THE ASSUMPTIONS OR METHODOLOGIES USED BY MR. SEELYE?

A. Yes. I have two material disagreements with Mr. Seelye's CCOSS.

Q. PLEASE OUTLINE YOUR TWO MATERIAL DISAGREEMENTS.

A. The two substantial disagreements that I have with Mr. Seelye are his "Modified Base-Intermediate-Peak" method to allocate generation costs and his classification of distribution plant between customer-related and demand-related.

A. <u>Generation</u>

Q. YOU INDICATE THAT ONE OF YOUR DISAGREEMENTS WITH MR. SEELYE IS HIS USE OF WHAT HE REFERS TO AS A MODIFIED BASE-INTERMEDIATE-PEAK METHOD TO ALLOCATE GENERATION COSTS. ARE THERE OTHER METHODOLOGIES WHICH MAY BE USED TO ALLOCATE GENERATION- RELATED PLANT AND EXPENSES?

A. Yes. There are several demand allocation methods utilized in the electric industry. The current National Association of Regulatory Utility Commissioners ("NARUC") <u>Electric Utility Cost Allocation Manual</u> discusses at least thirteen embedded demand allocation methods, while Dr. James Bonbright noted the existence of at least 29 demand allocation methods in his treatise, <u>Principles of Public Utilities Rates</u>.

Q. WHY DO SO MANY GENERATION ALLOCATION METHODS EXIST FOR THE ELECTRIC INDUSTRY?

A. Utilities design and build generation facilities to meet the energy and demand requirements of their customers on a collective basis. Because of this, and the physical laws of electricity, it is impossible to determine which customers are being served by which facilities. As such, production facilities are joint costs; i.e., used by all customers. Because of this commonality, production-related costs are not directly known for any customer or customer group and must somehow be allocated.

If all customer classes used electricity at a constant rate throughout the year, there would be no disagreement as to the proper assignment of generation-related costs: all analysts would agree that energy usage in terms of kWh would be the proper approach to reflect cost causation and cost incidence. However, such is not the case in that KU experiences periods (hours) of much higher demand during certain times of the year and across various hours of the day. Moreover, all customer classes do not contribute in equal proportions to these varying demands placed on the generation system. To complicate matters, the electric utility industry is somewhat unique in that there is a distinct energy/capacity trade-off relating to generation costs. That is, utilities design their mix of production facilities (generation and power supply) to minimize the total costs of energy and capacity, while also ensuring there is enough available capacity to meet peak demands. The trade-off occurs between the level of fixed investment per unit of capacity (KW) and the variable cost of producing a unit of output (kWh). Coal and nuclear units require high capital expenditures resulting in large investments per KW, whereas smaller units with higher variable production costs generally require significantly less investment per KW. Due to varying levels of demand placed on the system over the course of each day, month, and year there is a unique optimal mix of production facilities for each utility that minimizes the total cost of capacity and energy; i.e., its cost of service.

Therefore, as a result of the energy/capacity cost trade-off, and the fact that the service requirements of each utility are unique, many different allocation methodologies have evolved in an attempt to equitably allocate joint production costs to individual classes.

Q. PLEASE EXPLAIN.

A. Total production costs vary each hour of the year. Theoretically, energy and capacity costs should be allocated to classes each and every hour of the year. This would result in 8,760 hourly allocations during non-leap years. Although such an analysis is certainly possible with today's technology, the time and cost necessary for such an undertaking would likely exceed the additional benefits obtained over simpler methods. This is because the analyst does not know precise class loads each and every hour, and subjective decisions must still be made regarding the assignment of fixed investment (capacity costs) to individual hours. With this practical constraint in mind, each method has its strengths and weaknesses regarding its reasonableness in reflecting cost causation as well as the cost and effort required to produce a study.

Q. BRIEFLY, DISCUSS THE STRENGTHS AND WEAKNESSES OF COMMON PRODUCTION COST ALLOCATION METHODOLOGIES.

A. A brief description of the most common fully allocated cost methodologies and attendant strengths and weaknesses are as follows:

Single Coincident Peak ("1-CP") -- The basic concept underlying the 1-CP method is that an electric utility must have enough capacity available to meet its customers' peak coincident demand. As such, advocates of the 1-CP method reason that customers (or classes) should be responsible for fixed capacity costs based on their respective contributions to this peak system load. The major advantages to the 1-CP method are that the concepts are easy to understand, the analyses required to conduct a CCOSS are relatively simple, and the data requirements are significantly less than some of the more complex methods.

The 1-CP method has several shortcomings, however. First, and foremost, is the fact that the 1-CP method totally ignores the capacity/energy trade-off inherent in the electric utility industry. That is, the sole criterion for assigning one hundred percent of fixed capacity costs is the classes' relative contributions to load during a single hour of the year. This method does not consider, in any way, the extent to which customers use these facilities during the other 8,759 hours of the year. This may have severe consequences because a utility's planning decisions regarding the amount and type of generation capacity to build and install is predicated not only on the maximum system load, but also on how customers demand electricity throughout the year, i.e., load duration. To illustrate, if a utility had a peak load of 15,000 MW and its actual optimal generation mix included an assortment of nuclear, coal, hydro, combined cycle and combustion turbine units, the total cost of capacity is significantly higher than if the utility only had to consider meeting 15,000 MW for 1 hour of the year. This is because the utility would install the cheapest type of plant, (i.e., peaker units) if it only had to consider one hour a year.

There are two other major shortcomings of the 1-CP method. First, the results produced with this method can be unstable from year to year. This is because the hour in which a utility peaks annually is largely a function of weather. Therefore, annual peak load depends on when severe weather occurs. If this occurs on a weekend or holiday, relative class contributions to the peak load will likely be significantly different than if the peak occurred during a weekday. The other major shortcoming of the 1-CP method is often referred to as the "free ride" problem. This problem can easily be seen with a summer peaking utility that peaks about 5:00 p.m. Because street lights are not on at this time of day, this class will not be assigned any capacity costs at all and enjoy a free ride on the assignment of generation costs that this class requires.

Summer and Winter Coincident Peak ("S/W Peak") -- The S/W Peak method was developed because some utilities' annual peak load occurs in the summer during some years and in the winter during others. Because customers' usage and load characteristics may vary by season, the S/W Peak attempts to recognize this characteristic. This method is essentially the same as the 1-CP method except that two hours of load are considered instead of one. This method has essentially the same strengths and weaknesses as the 1-CP method, and in my opinion, is only marginally more reasonable than the 1-CP method. However, it is my understanding that KU is consistently a summer peaking utility. Therefore, this methodology is likely not well suited in this instance.

Twelve Monthly Coincident Peak ("12-CP") -- Arithmetically, the 12-CP method is essentially the same as the 1-CP method except that class contributions to each monthly peak are considered. Although the 12-CP method bears little resemblance to how utilities design and build their systems, the results produced by this method better reflect the cost incidence of a utility's generation facilities.

Most electric utilities have distinct seasonal load patterns such that there are high system peaks during the winter and summer months, and significantly lower system peaks during the spring and autumn months. By assigning class responsibilities based on their respective contributions throughout the year, consideration is given to the fact that utilities will call on all of their resources during the highest peaks, and only use their most efficient plants during lower peak periods. Therefore, the capacity/energy trade-off is implicitly considered to a small extent under this method.

The major shortcoming of the 12-CP method is that accurate load data is required by class throughout the year. This generally requires a utility to maintain on-going load studies. However, once a system to record class load data is in place, the administration and maintenance of such a system is not overly cumbersome for larger utilities.

Peak and Average ("P&A") -- The various P&A methodologies rest on the premise that a utility's actual generation facilities are placed into service to meet peak load and serve consumers demands throughout the entire year. Hence, the P&A method assigns capacity costs partially on the basis of contributions to peak load and partially on the basis of consumption throughout the year. Although there is not universal agreement on how peak demands should be measured or how the weighting between Peak and Average demands should be performed, many P&A studies use class contributions to coincident-peak demand for the "peak" portion, while some studies weight the Peak and Average loads based on the system coincident load factor and others give equal weight to energy usage and peak demand.

The major strengths of the P&A method are that an attempt is made to recognize the capacity/energy trade-off in the assignment of fixed capacity costs, and that data requirements are minimal.

Although the recognition of the capacity/energy trade-off is admittedly arbitrary under the P&A method, most other allocation methods also suffer to some degree of arbitrariness.

Average and Excess ("A&E") -- The A&E method also considers both peak demands and energy consumption throughout the year. However, the A&E method is much different than the P&A method in both concept and application. The A&E method recognizes class load diversity within a system, such that all classes do not call on the utility's resources to the same degree, at the same times. Mechanically, the A&E method weights average and excess demands based on system coincident load factor. Individual class "excess" demands represent the difference between the class non-coincident peak demand and its average annual demand. The classes' "excess" demands are then summed to determine the system excess demand. Under this method, it is important to distinguish between coincident and non-coincident demands. This is because if coincident, instead of non-coincident, demands are used when calculating class excesses, the end result will be exactly the same as that achieved under 1-CP method.

Although the A&E method bears virtually no resemblance to how generation systems are designed, this method can produce fair and reasonable results for many utilities. This is because no class will receive a free-ride under this method, and because recognition is given to average consumption as well as to the additional costs imposed by not maintaining a perfectly constant load.

A potential shortcoming of this method is that customers that only use power during off-peak periods will be overburdened with costs. Under the A&E method, off-peak customers will be assigned a higher percentage of capacity costs because their non-coincident load factor may be very low even though they call on the utility's resources only during cheap off-peak periods.

Equivalent Peaker ("EP") -- The EP method combines certain aspects of traditional embedded cost methods with those used in forward-looking marginal cost studies. The EP method often relies on planning information in order to classify individual generating units as energy- or demand-related and considers the need for a mix of base load intermediate and peaking generation resources.

The EP method has substantial intuitive appeal in that base load units that operate with high capacity factors are allocated largely on the basis of energy consumption with costs shared by all classes based on their usage, while peaking units that are seldom used and only called upon during peak load periods are allocated based on peak demands to those classes contributing to the system peak load. However, this method requires a significant amount of data.

Base-Intermediate-Peak ("BIP") -- The BIP method is an accepted allocation approach that attempts to recognize the capacity/energy trade-off that actually exists within a utility's portfolio of generation assets. A utility's base load units tend to run during all periods of the year; i.e., both peak load periods as well as to satisfy energy requirements in the most efficient manner possible during minimum demand periods (e.g., during the middle of the night). Because base load units operate regardless of peak requirements, they are most appropriately classified as energy-related. At the opposite end of the spectrum are peaking units, such as combustion turbines. These units operate with high variable costs and are only utilized to help meet peak period demands. As such, peakers are classified as peak demand-related. Intermediate plants (e.g., many combined cycle units) are not as efficient as large base load plants but more efficient than peaking units. For this reason, Intermediate plants are not called upon (dispatched) during periods of minimum (base) load but are dispatched before, and more frequently, than peaker units. Therefore, Intermediate plants can be said to serve a dual purpose: partially energy-related and partially demand-related. Intermediate plants are typically classified as partially energy-related and partially demand-related based on their respective capacity factors.[2] In my opinion, the BIP method is an excellent cost allocation approach for many utilities as it captures the actual differences in the capacity/energy trade-off that exist across a utility's generation mix. The BIP method may not be appropriate for utilities that purchase the majority of their energy needs or for utilities with an inefficient mix of generating resources.

Q. MR. WATKINS, YOU HAVE DISCUSSED THE STRENGTHS AND WEAKNESSES OF THE MORE COMMON GENERATION ALLOCATION METHODOLOGIES. ARE ANY OF THESE METHODS CLEARLY INFERIOR IN YOUR VIEW?

A. Yes. In my opinion the 1-CP and seasonal CP (such as 4-CP) methods do not reasonably reflect cost causation for integrated electric utilities because these methods totally ignore the utilization of a utility's facilities. Perhaps the simplest way to explain this is to consider that the methodology selected is used to allocate Generation plant

[2] Capacity factor is the ratio of average utilization (output) over a year to peak hour output.

investment. Generation investment costs vary from a low of a few hundred dollars per KW of capacity for high running cost (energy cost) peakers to several thousand dollars per KW for base load nuclear facilities with low running costs. If a utility were only concerned with being able to meet peak load with no regard to running costs, it would simply install inexpensive peakers. Under such an unrealistic system design, plant costs would be much lower than in reality but running costs; i.e., variable fuel costs would be astronomical, and would result in a higher overall cost to serve customers. The 1-CP and seasonal CP methods totally ignore this very important fact.

Q. MR. SEELYE HAS USED WHAT HE REFERS TO AS A MODIFIED BIP METHOD TO ALLOCATE GENERATION COSTS. DID HE CALCULATE THE BIP METHOD IN A REASONABLE MANNER?

A. Mr. Seelye's Modified BIP method does not follow the generally accepted BIP approach, and in fact, I have never seen Mr. Seelye's method used before. However, I would be reluctant to say his approach is totally unreasonable.

Whereas Mr. Seelye's Modified BIP method does allocate a portion of generation facilities based on energy and a portion on peak demands, his approach does not reflect the actual mix of supply resources utilized by KU. At this point, it should be noted that LG&E's and Kentucky Utilities' ("KU") generation resources are centrally dispatched. Both Mr. Seelye and I have recognized this combined central dispatch in our allocation studies. When I refer to KU's actual generation resources, I am referring to the joint resources of LG&E and KU and not the individual legal ownership of these plants for booking purposes.

The traditional BIP method is a supply-based approach that classifies generation plant between energy-related and demand-related; i.e., it considers the actual supply characteristics of a utility's generation portfolio. These supply based classifications are then allocated to classes based on demand-side criteria (kWh usage and peak demand).

Mr. Seelye's approach ignores the actually supply-side characteristics of EON's generation portfolio because it only considers relative differences in system usages and demands. In fact, given KU's customers combined usage and demand profiles, Mr. Seelye's approach would classify a utility's generation investment exactly the same regardless of its actual portfolio mix of plants. Mr. Seelye's classification would be identical if KU's portfolio mix was comprised entirely of base load units or entirely of peaking units. In my opinion, this assumption (or result) is not consistent with the intent of the BIP method. Namely, to recognize the capacity/energy tradeoff actually present in a system.

Q. HAVE YOU CONDUCTED A CLASS COST OF SERVICE STUDY USING A TRADITIONAL BIP APPROACH?

A. Yes.

Q. PLEASE EXPLAIN HOW YOU CONDUCTED YOUR TRADITIONAL BIP METHOD.

A. During the discovery phase of this proceeding, KU provided the hourly loads (output) of each EON generation unit during the test year. In other words, for each EON generating unit, I was provided hourly output during the test year. With this data, I examined the timing, frequency, and level of dispatch for each EON generating unit. This examination revealed clear and distinct patterns for individual generating units. Many units are clearly base load in nature, others are clearly peaker facilities, and some units are neither base load or clearly peaker, but intermediate plants. From this examination, I was able to classify each generating unit as base, intermediate, or peak. Base load plants were classified as 100% energy-related, peaker units were classified as 100% demand-related, and intermediate plants were classified as partially energy-related and partially demand-related based on their individual capacity factors. The results of my BIP generation classification is presented in my Schedule GAW_3. It should be noted that EON's hydroelectric facilities were classified as 100% energy-related as these facilities are largely run-of-river or flood control dams. My BIP classification study results in the following aggregate generation classification:

Energy-related:	82.78%
Demand-related:	17.22%

Q. **WHAT ARE THE CLASS RATES OF RETURN ON RATE BASE AT CURRENT RATES UTILIZING YOUR TRADITIONAL BIP METHOD TO CLASSIFY GENERATION PLANT?**

A. Individual class rates of return utilizing the traditional BIP classification method, compared to Mr. Seelye's Modified BIP are presented below:

Class	OAG Traditional BIP	Seelye Modified BIP
RS	4.73%	3.58%
GSS	11.66%	12.20%
GSP	10.62%	4.79%
AES	9.48%	6.32%
LPS	9.49%	11.53%
LPP	8.99%	11.82%
LPT	10.10%	10.07%
STODS	4.80%	6.73%
STODP	5.42%	6.92%
LCIP	6.09%	8.55%
LCIT	3.64%	5.54%
MPP	14.97%	12.88%
MPT	13.95%	13.35%
LMPP	11.20%	11.42%
LMPT	10.57%	13.40%
LITOD	18.39%	25.00%
SL	5.04%	4.51%
SLDEC	7.86%	6.87%
POL	10.04%	13.27%
OL	14.89%	16.28%
TOTAL COMPANY	7.15%	7.15%

B. <u>Distribution</u>

Q. **AS WE MOVE DOWNSTREAM FROM GENERATION THROUGH TRANSMISSION, TO THE DISTRIBUTION SYSTEM, HOW HAS THE COMPANY ASSIGNED DISTRIBUTION COSTS TO RATE SCHEDULES AND CUSTOMER CLASSES?**

A. Mr. Seelye has allocated Distribution plant and expenses partially on the basis of number of customers and partially on the basis of peak demand. I concur with Mr.

Seelye's selection of customer and demand allocators for Distribution plant. However, there is often controversy regarding the portion of Distribution plant that should be allocated on number of customers and the portion that should be allocated on demand. This separation between customer-related and demand-related Distribution plant is referred to as the classification of Distribution plant.

Q. PLEASE EXPLAIN THE TERM "CLASSIFICATION OF DISTRIBUTION PLANT."

A. In the broadest sense, an embedded CCOSS is undertaken using a three-tiered approach. First, costs are functionalized as Production, Transmission, Distribution, General, and/or customer. These functionalized costs are then classified as energy, demand, or customer-related. Finally, classified costs are then allocated to individual classes. With respect to the classification of Distribution plant, it is generally recognized that there are no energy-related costs. That is, the distribution system is designed to meet localized peak demands. However, largely as a result of differences in customer densities throughout a utility's service area, electric utility Distribution plant often is classified as partially demand-related and partially customer-related.

Q. WHY IS THE CLASSIFICATION OF DISTRIBUTION PLANT IMPORTANT IN CCOSS ANALYSES?

A. The classification of Distribution plant may be the single most important factor affecting class rates of return. To illustrate the importance of this issue, consider the Residential class: whereas this class may account for only 40% to 50% of peak demand, it is responsible for a much higher percentage of the number of customers. Therefore, given the level of investment associated with Distribution plant, wide variations in class rates of return can result from different customer/demand classifications.

Q. WHY ARE THE DIFFERENCES IN CUSTOMER DENSITIES IMPORTANT IN THE ASSIGNMENT OF DISTRIBUTION COSTS TO INDIVIDUAL CLASSES?

A. Possibly the best way to answer this question is by way of example. Consider two different electric utilities: one similar to KU with urban, suburban, and rural service areas and one similar to Consolidated Edison Company, which is mainly urban. With respect to the utility with a rural service area, many miles of conductors and associated plant must be installed in order to serve the demands of relatively few customers. Conversely, many more customers are served on a per mile basis for the urban utility. For the urban utility, it may be fair and reasonable to allocate Distribution plant solely on the basis of peak demands. However, with respect to the utility with a rural service area, such an allocation may be unfair if some classes are located mainly in urban or suburban areas, while other classes of customers are located in urban, suburban, and rural areas. As a result, many utilities classify Distribution plant as partially demand- related and partially customer-related. In this manner, a portion of Distribution plant is allocated based on a peak demand, and a portion allocated based on number of customers.

Q. HOW DOES ONE DETERMINE HOW MUCH DISTRIBUTION PLANT SHOULD BE CLASSIFIED AS DEMAND-RELATED AND HOW MUCH AS CUSTOMER-RELATED?

A. Once the decision is made that Distribution plant should be allocated considering both peak demand and number of customers, there are two generally accepted methods for determining the portions or percentages that should be allocated on each basis. These two methods are known as the minimum size and zero-intercept approaches. Under both methods, a study is conducted for each major plant account within the distribution system. That is, each account is studied and assigned its own customer and demand components.

The minimum size method rests on the premise that the minimum, or smallest size, installed equipment makes up the distribution network to connect customers to the distribution system, and that all larger sizes of equipment serve peak demands. In practice, the cost per unit of the smallest sized installed equipment is determined. This minimum cost per unit is then multiplied by the total number units in the system to arrive at a total customer amount. The total customer amount is then divided by the total cost for the account to determine the customer percentage. As the compliment, one minus the customer percentage equals the demand percentage.

The zero-intercept method is similar to the minimum size method, except for the determination of the minimum cost per unit. The zero-intercept method recognizes that even the smallest installed piece of equipment has a demand component, because it too is designed and installed to meet the peak load placed on that equipment. The zero-intercept method attempts to arrive at the "theoretical" cost of a piece of plant or equipment capable of carrying zero load. This is accomplished using statistical regression techniques whereby the per unit costs of various sizes of equipment are determined and a best fitting line is fitted into an equation form. The point at which the fitted line intersects the cost axis at zero size is called the zero-intercept. The zero-intercept cost then serves as the minimum, or zero size, cost per unit.

Q. IS ONE METHOD PREFERRED OVER THE OTHER?

A. In general, I prefer to use the zero-intercept method when possible and appropriate. However, as with most aspects of ratemaking where there is not a universally accepted formula, each approach has its advantages and disadvantages. The major criticisms I have regarding the minimum size method is that this method tends to overstate the customer percentage because even the smallest installed size is used to meet some level of peak demand. The primary weaknesses of the zero-intercept method are that more data and a good working knowledge of statistical linear regression analyses are required, and sometimes there is no strong correlation between costs and sizes (capacity) of distribution equipment.

Q. HOW APPROPRIATE IS EITHER METHOD FROM A DESIGN OR OPERATIONAL PERSPECTIVE?

A. First and foremost, the classification of Distribution plant as partially customer-related and partially demand-related results from the view that the allocation of these plant items based solely on peak demands would not be equitable to some classes. I emphasize this point, because many analysts "lose sight of the forest for the trees". When classifying individual accounts within Distribution plant, analysts sometimes ignore (or do not understand) how a distribution system is designed and connected.

There are three major factors the analyst should keep in mind when classifying Distribution plant. First, there are often alternatives across plant and equipment. For example, the need for a particular transformer may be erased if a larger size conductor is used. Alternatively, fewer and smaller poles may be required if lighter conductors are used. Second, and more importantly, is the fact that purchasing economies are usually present. For example, there are dozens of various types of overhead conductors manufactured. However, due to purchasing economies, a utility may only purchase a few different sizes of conductor. This may result in some "over capacity", yet, the total installed cost is less than if every segment of the system is optimally designed. Third, most components of the distribution system are somewhat oversized for other reasons such as safety, reliability, and growth uncertainty.

Although, these three factors are reflective of how distribution systems are actually designed and installed, neither the minimum size nor the zero-intercept method account for these factors. In fact, the presence of these three factors can seriously skew the results of either method. If the weakness is not captured or recognized, inequitable class allocations may result.

Q. HOW DID MR. SEELYE CLASSIFY DISTRIBUTION PLANT BETWEEN CUSTOMER-RELATED AND DEMAND-RELATED COMPONENTS?

A. My Seelye claims to have conducted a zero-intercept analysis to develop customer/demand classifications for distribution Overhead lines, underground lines, and transformers. I take exception to Mr. Seelye's reference to his proposed classifications as a "zero-intercept" derived study, and I disagree with his approach.

Q. PLEASE EXPLAIN HOW AN INDUSTRY ACCEPTED ZERO-INTERCEPT STUDY IS CONDUCTED.

A. Under accepted industry practices, which are well documented in various cost allocation manuals,[3] the zero-intercept method is very straight-forward. First, various types of equipment are separated by size and type. Next, historical accounting costs are

[3] See for example the National Association of Regulatory Utility Commissions ("NARUC") Electric Utility Cost Allocation Manual, 1992, pages 92 through 94.

trended by vintage year to reflect cost differences over time. For each size and type of equipment, the total dollars and total units (feet or number of units) are considered as well as the capacity (size) of each type of equipment. Because the overall objective is to estimate the cost of a "zero-size" piece of equipment, total costs are divided by total units (feet or unit) for each type of equipment to derive an average cost per foot or per unit. A regression model is then developed based on the following form:

$$\text{cost/unit} = a + b\ (\text{size})$$

The resulting intercept (a) produces the estimated cost per unit of a "zero-size" piece of equipment. This estimated zero-size cost per unit is then multiplied by the total units in the system to estimate a zero-size total cost. The ratio of total zero size costs to trended total actual costs represents the percentage of zero-size equipment and serves as the customer percentage.

The above industry standard is in stark contrast to Mr. Seelye's method presented in his Seelye Exhibits 20, 21, and 22. Mr. Seelye refers to his approach as a "weighted regression analysis." Although this "weighted regression analysis" is a clever arithmetic exercise, it violates theoretical statistical principles of linear regression and skews his results. Moreover, on page 64 of his direct testimony, Mr. Seelye states:

> "Like most electric utilities, the number of feet of conductors on KU's system is not uniformly distributed over all sizes of wire. For example, KU has over 20.9 million feet of #2 copper overhead conductor, but only 660 feet of 556 MCM overhead conductor. For this reason, it was necessary to use a weighted regression analysis, instead of a standard least-squares analysis, in the determination of the zero intercept."

It is interesting at best that Mr. Seelye finds KU's system to be typical of other utilities, yet, his approach varies dramatically from the industry practice that has been used by countless utilities, Commissions, and analysts for decades.

To understand the bias in Mr. Seelye's "weighted regression analysis," we must fully understand the mathematical model he derives. Using Overhead conductors as an example, consider Mr. Seelye's analysis presented in his Exhibit 20. Although not shown in his exhibit, Mr. Seelye's equation for Overhead conductors is:

$$(\text{cost per foot x feet}^{0.5}) = 0 + 1.5562(\text{feet}^{0.5}) + 0.00244(\text{capacity x feet}^{0.5})$$

Notice that the equation's true intercept is forced to zero. However, if capacity is set to zero, the second term [0.00244(capacity x feet$^{0.5}$)] becomes zero. If we then ask what is the cost for a foot of a zero capacity conductor we see that feet$^{0.5}$ = 1$^{0.5}$ = 1, such that the cost for one foot becomes $1.5562. This is the zero-intercept used by Mr. Seelye.

To illustrate the bias in Mr. Seelye's analysis, consider the following hypothetical example of his approach for a system "not uniformly distributed over all sizes of wire":

Total	Cost Per Foot (y)	Capacity (x)	Feet (n)	y($n^{0.5}$)	$n^{0.5}$	x($n^{0.5}$)
350.00	3.50	2.00	100	35	10.00	20.00
250.00	5.00	4.00	50	35.355339	7.07	28.28
62,500.00	6.25	6.00	10,000	625	100.00	600.00
164.00	8.20	8.00	20	36.671515	4.47	35.78
99.50	9.95	10.00	10	31.464663	3.16	31.62

Under the correct, and accepted zero-intercept method, the following regression equation results:

$$\text{cost/feet} = 1.75 + 0.805(\text{size})$$

Therefore, a zero-size cost is estimated to be $1.75 per foot. Using the same data, the following equation is produced using Mr. Seelye's approach:

$$\text{cost per foot x feet}^{0.5} = 0 + 1.9815(\text{feet}^{0.5}) + 0.7120(\text{size x feet}^{0.5})$$

Mr. Seelye's approach results in a zero cost per foot of $1.9815 as compared to the industry accepted cost per foot of $1.75.

Q. DO YOU HAVE ANY OTHER SIGNIFICANT DISAGREEMENTS WITH MR. SEELYE'S DISTRIBUTION PLANT CLASSIFICATION STUDIES?

A. Yes. Because a utility's distribution plant is comprised of many different vintage years of equipment, it is necessary to trend original cost (booked) amounts to constant or current dollars. This is particularly important because certain types of equipment may have been installed as standard practice several years ago (and are still in service) but are not utilized today (with higher costs due to inflation). As such, the trending of equipment costs is critical to measure various vintage years plant on a consistent (apples to apples) basis. Although Mr. Seelye utilized this required trending concept in his analyses for LG&E, distribution plant costs were not trended for his KU analyses.

Q. WHAT ARE THE RESULTS OF MR. SEELYE'S CLASSIFICATION OF DISTRIBUTION PLANT?

A. Mr. Seelye classifies distribution plant as follows:

Account	Percentage Customer	Percentage Demand
Overhead Conductors	78.92%	21.08%
Underground Conductors	72.14%	27.86%
Lines Transformers	47.88%	52.12%

Q. HAVE YOU CONDUCTED AN INDEPENDENT ANALYSIS TO CLASSIFY KU'S DISTRIBUTION PLANT?

A. Yes. Because KU's distribution plant costs were not trended to constant dollars, I could not conduct a reasonable analysis for KU with the data available. As such, I utilized the constant dollar data for LG&E as used by Mr. Seelye in the LG&E case, and used my customer/demand percentages developed in that case as a surrogate for KU. The following are my estimated customer/demand classifications:

Account	Percentage Customer	Percentage Demand
Overhead Conductors	39.3%	60.7%
Underground Conductors	20.1%	79.9%
Line Transformers	26.5%	73.5%

Q. WHAT ARE YOUR CCOSS RESULTS USING THESE CUSTOMER/DEMAND CLASSIFICATIONS?

A. My recommended distribution plant classifications coupled with a traditional BIP approach to classify generation resources are reflected in my recommended CCOSS. The detail of this CCOSS is provided in my Schedule GAW_4 and are summarized below:

Class	ROR At Current Rates	
	OAG Recommended	Seelye
RS	5.36%	3.58%
GSS	11.43%	12.20%
GSP	8.70%	4.79%
AES	7.68%	6.32%
LPS	8.48%	11.53%
LPP	8.01%	11.82%
LPT	10.10%	10.07%
STODS	3.95%	6.73%
STODP	4.72%	6.92%
LCIP	5.30%	8.55%
LCIT	3.64%	5.54%
MPP	13.17%	12.88%
MPT	13.96%	13.35%
LMPP	9.70%	11.42%
LMPT	10.57%	13.40%
LITOD	15.67%	25.00%
SL	6.13%	4.51%
SLDEC	8.71%	6.87%
POL	15.42%	13.27%
OL	19.06%	16.28%
TOTAL COMPANY	7.15%	7.15%

As can be seen above, my CCOSS study which is based on accepted industry practices, produces significantly different results than those obtained by Mr. Seelye.

ELECTRIC CLASS REVENUE DISTRIBUTION

Q. PLEASE DESCRIBE KU'S PROPOSED DISTRIBUTION OF ITS REQUESTED OVERALL ELECTRIC REVENUE INCREASE TO INDIVIDUAL CUSTOMER CLASSES.

A. KU witness Seelye presents the Company's proposed distribution of its requested $19.57 million revenue increase to customer classes. In large part, Mr. Seelye proposes that the Residential and lighting classes should be responsible for the vast majority of the rate increase proposed by KU. According to Mr. Seelye, this proposed increase is based on his CCOSS results.

A summary of KU's proposed revenue increase for each customer class is shown below:

	KU Proposed Electric Increase		
Class	Amount	Percent	Percent of Avg.
RS	$17,329,356	4.47%	233%
GSS	0	0.00%	0%
GSP	446,784	16.04%	837%
AES	321,938	4.56%	238%
LPS	0	0.00%	0%
LPP	0	0.00%	0%
LPT	-70,621	-5.87%	-306%
STODS	82,070	0.99%	52%
STODP	6,637	1.00%	52%
LCIP	0	0.00%	0%
LCIT	-38,022	-0.13%	-7%
MPP	575,463	8.99%	469%
MPT	100,123	2.81%	147%
LMPP	29,196	0.67%	35%
LMPT	5,099	0.04%	2%
LITOD	0	0.00%	0%
SL	304,645	4.29%	224%
SLDEC	61,720	4.86%	253%
POL	195,020	4.89%	255%
OL	224,423	3.88%	202%
TOTAL COMPANY	$19,573,831	1.92%	100%

Q. MR. WATKINS, IN YOUR OPINION ARE KU'S PROPOSED CUSTOMER CLASS REVENUE INCREASES REASONABLE?

A. No.

Q. DO YOU HAVE AN ALTERNATIVE REVENUE INCREASE DISTRIBUTION TO THAT PROPOSED BY MR. SEELYE?

A. Yes, I do. Using the results of my CCOSS as a guide, and also considering principles of gradualism, fairness and equity, I propose an equitable and cost based mechanism to assign class revenue increases at KU's requested overall revenue level. My proposed revenue distribution is presented in my Schedule GAW_5 and results in the following class increases:

Class	OAG Proposed Electric Increase Amount	Percent	Percent of Avg.
RS	$9,723,431	2.51%	131%
GSS	1,247,416	0.96%	50%
GSP	40,057	1.44%	75%
AES	135,329	1.92%	100%
LPS	2,791,882	1.44%	75%
LPP	1,097,194	1.44%	75%
LPT	17,314	1.44%	75%
STODS	197,889	2.40%	125%
STODP	15,889	2.40%	125%
LCIP	2,799,307	2.40%	125%
LCIT	725,336	2.40%	125%
MPP	61,379	0.96%	50%
MPT	34,135	0.96%	50%
LMPP	62,624	1.44%	75%
LMPT	176,886	1.44%	75%
LITOD	199,504	0.96%	50%
SL	136,254	1.92%	100%
SLDEC	18,275	1.44%	75%
POL	38,266	0.96%	50%
OL	55,464	0.96%	50%
TOTAL COMPANY	$19,573,831	1.92%	100%

My specific electric revenue allocation methodology is as follows, with the actual calculations provided in Schedule GAW_5.

First, I recognize class cost of service and the concept of gradualism. In doing so, I recommend a graduated scale of increases such that no class receives a rate decrease and that all class increases are limited to a range of 50% of the system average percentage increase to 150% of the system average increase. In order to recognize the higher than system average ROR's provided by certain classes, I increased these higher than average ROR classes less than the system average percentage. Similarly, those classes with low rates of return were increased by a higher percentage. Finally, due to its size relative to the system, the Residential class was treated as a residual.

Q. MR. WATKINS, PLEASE PROVIDE YOUR RECOMMENDED SCALE BACK METHOD TO ASSIGN CLASS REVENUE INCREASES SHOULD THE COMMISSION AUTHORIZE AN OVERALL REVENUE REQUIREMENT INCREASE LESS THAN THAT PROPOSED BY KU OR AN OVERALL DECREASE AS RECOMMENDED BY THE OAG.

A. I recommend that my customer class revenue increases be reduced proportionally downward.

<u>RESIDENTIAL ELECTRIC RATE DESIGN</u>

Q. PLEASE DESCRIBE KU'S CURRENT RESIDENTIAL RATE STRUCTURE?

A. Currently, Residential rates include a fixed monthly customer charge of $5.00 and a flat kWh energy charge.

Q. WITH RESPECT TO THE CURRENT RESIDENTIAL CUSTOMER CHARGE OF $5.00, DOES KU PROPOSE AN INCREASE TO THIS FIXED MONTHLY RATE?

A. Yes. KU proposes an increase to the monthly Residential customer charge from the current $5.00 level to $8.49.

Q. DOES MR. SEELYE PROVIDE ANY JUSTIFICATION FOR THE LARGE INCREASE IN THE FIXED CUSTOMER CHARGE?

A. As part of his CCOSS, Mr. Seelye functionalizes all costs that include an assignment of overheads to each functional and classification category. Within Mr. Seelye's CCOSS, these fully allocated costs that are classified as "customer" equate to a monthly residential "customer allocated cost" of $16.61.

Q. DO YOU AGREE WITH MR. SEELYE'S "CUSTOMER COST" ANALYSIS?

A. No. Mr. Seelye's customer cost analysis includes not only those costs that are directly attributable to customers but also assigns a significant level of corporate overhead costs. In my opinion, any customer cost analysis used as a basis for establishing fixed monthly customer charges should only include direct customer costs.

Q. HAVE YOU CONDUCTED SUCH A DIRECT CUSTOMER COST ANALYSIS?

A. Yes. The results of my direct customer costs analysis are presented in my Schedule GAW_6 and result in a monthly Residential customer cost of $4.36.

Q. WHAT IS YOUR RECOMMENDATION AS TO RESIDENTIAL CUSTOMER CHARGES IN THIS CASE?

A. Given that my direct customer cost analysis results in a monthly customer cost of $4.36, I recommend maintaining the current monthly customer charge of $5.00 regardless of any increase or decrease in revenue requirement authorized by this Commission.

Q. DOES KU'S PROPOSED 70% INCREASE TO THE RESIDENTIAL CUSTOMER CHARGE PROMOTE OR DISCOURAGE CONSERVATION?

A. KU's proposed increased reliance on customer charge revenue will discourage conservation from its electric customers as a larger percentage of customers' bills will be collected from a fixed monthly charge that does not vary with usage. As such, the Company proposed 70% increase to the fixed customer charge would send a price signal to customers that is contrary to conservation efforts and encourage additional usage of electricity.

Q. DOES THIS COMPLETE YOUR TESTIMONY?

A. Yes.

BACKGROUND & EXPERIENCE PROFILE
GLENN A. WATKINS
VICE PRESIDENT/SENIOR ECONOMIST
TECHNICAL ASSOCIATES, INC.

EDUCATION

1982 - 1988	M.B.A., Virginia Commonwealth University, Richmond, Virginia
1980 - 1982	B.S., Economics; Virginia Commonwealth University
1976 - 1980	A.A., Economics; Richard Bland College of The College of William and Mary, Petersburg, Virginia

POSITIONS

Jul. 1995-Present	Vice President/Senior Economist, Technical Associates, Inc.
Mar. 1993-1995	Vice President/Senior Economist, C. W. Amos of Virginia
Apr. 1990-Mar. 1993	Principal/Senior Economist, Technical Associates, Inc.
Aug. 1987-Apr. 1990	Staff Economist, Technical Associates, Inc., Richmond, Virginia
Feb. 1987-Aug. 1987	Economist, Old Dominion Electric Cooperative, Richmond, Virginia
May 1984-Jan. 1987	Staff Economist, Technical Associates, Inc.
May 1982-May 1984	Economic Analyst, Technical Associates, Inc.
Sep. 1980-May 1982	Research Assistant, Technical Associates, Inc.

EXPERIENCE

I. Public Utility Regulation

A. Costing Studies -- Conducted, and presented as expert testimony, numerous embedded and marginal cost of service studies. Cost studies have been conducted for electric, gas, telecommunications, water, and wastewater utilities. Analyses and issues have included the evaluation and development of alternative cost allocation methods with particular emphasis on ratemaking implications of distribution plant classification and capacity cost allocation methodologies. Distribution plant classifications have been conducted using the minimum system and zero-intercept methods. Capacity cost allocations have been evaluated using virtually every recognized method of allocating demand related costs (e.g., single and multiple coincident peaks, non-coincident peaks, probability of loss of load, average and excess, and peak and average).

Embedded and marginal cost studies have been analyzed with respect to the seasonal and diurnal distribution of system energy and demand costs, as well as cost effective approaches to incorporating energy and demand losses for rate design purposes. Economic dispatch models have been evaluated to determine long range capacity requirements as well as system marginal energy costs for ratemaking purposes.

B. Rate Design Studies -- Analyzed, designed and provided expert testimony relating to rate structures for all retail rate classes, employing embedded and marginal cost studies. These rate structures have included flat rates, declining block rates, inverted block rates, hours use of demand blocking, lighting rates, and interruptible rates. Economic development and special industrial rates have been developed in recognition of the competitive environment for specific customers. Assessed alternative time differentiated rates with diurnal and seasonal pricing structures. Applied Ramsey (Inverse Elasticity) Pricing to marginal costs in order to adjust for embedded revenue requirement constraints.

GLENN A. WATKINS

C. Forecasting and System Profile Studies -- Development of long range energy (Kwh or Mcf) and demand forecasts for rural electric cooperatives and investor owned utilities. Analysis of electric plant operating characteristics for the determination of the most efficient dispatch of generating units on a system-wide basis. Factors analyzed include system load requirements, unit generating capacities, planned and unplanned outages, marginal energy costs, long term purchased capacity and energy costs, and short term power interchange agreements.

D. Cost of Capital Studies -- Analyzed and provided expert testimony on the costs of capital and proper capital structures for ratemaking purposes, for electric, gas, telephone, water, and wastewater utilities. Costs of capital have been applied to both actual and hypothetical capital structures. Cost of equity studies have employed comparable earnings, DCF, and CAPM analyses. Econometric analyses of adjustments required to electric utilities cost of equity due to the reduced risks of completing and placing new nuclear generating units into service.

E. Accounting Studies -- Performed and provided expert testimony for numerous accounting studies relating to revenue requirements and cost of service. Assignments have included original cost studies, cost of reproduction new studies, depreciation studies, lead-lag studies, Weather normalization studies, merger and acquisition issues and other rate base and operating income adjustments.

II. Transportation Regulation

A. Oil and Products Pipelines -- Conducted cost of service studies utilizing embedded costs, I.C.C. Valuation, and trended original cost. Development of computer models for cost of service studies utilizing the "Williams" (FERC 154-B) methodology. Performed alternative tariff designs, and dismantlement and restoration studies.

B. Railroads -- Analyses of costing studies using both embedded and marginal cost methodologies. Analyses of market dominance and cross-subsidization, including the implementation of differential pricing and inverse elasticity for various railroad commodities. Analyses of capital and operation costs required to operate "stand alone" railroads. Conducted cost of capital and revenue adequacy studies of railroads.

III. Insurance Studies

Conducted and presented expert testimony relating to market structure, performance, and profitability by line and sub-line of business within specific geographic areas, e.g. by state. These studies have included the determination of rates of return on Statutory Surplus and GAAP Equity by line - by state using the NAIC methodology, and comparison of individual insurance company performance vis a vis industry Country-Wide performance.

Conducted and presented expert testimony relating to rate regulation of workers compensation, automobile, and professional malpractice insurance. These studies have included the determination of a proper profit and contingency factor utilizing an internal rate of return methodology, the development of a fair investment income rate, capital structure, cost of capital.

Other insurance studies have included testimony before the Virginia Legislature regarding proper regulatory structure of Credit Life and P&C insurance; the effects on competition and prices resulting from proposed insurance company mergers, maximum and minimum expense multiplier limits, determination of specific class code rate increase limits (swing limits); and investigation of the reasonableness of NCCI's administrative assigned risk plan and pool expenses.

GLENN A. WATKINS

IV. Anti-Trust and Commercial Business Damage Litigation

Analyses of alleged claims of attempts to monopolize, predatory pricing, unfair trade practices and economic losses. Assignments have involved definitions of relevant market areas(geographic and product) and performance of that market, the pricing and cost allocation practices of manufacturers, and the economic performance of manufacturers' distributors.

Performed and provided expert testimony relating to market impacts involving automobile and truck dealerships, incremental profitability, the present value of damages, diminution in value of business, market and dealer performance, future sales potential, optimal inventory levels, fair allocation of products, financial performance; and business valuations.

MEMBERSHIPS AND CERTIFICATIONS

Member, Association of Energy Engineers (1998)
Certified Rate of Return Analyst, Society of Utility and Regulatory Financial Analysts (1992)
Member, American Water Works Association
National Association of Business Economists
Richmond Association of Business Economists
National Economics Honor Society

KENTUCKY UTILITIES

OAG Adjustment to Reflect Electric Weather Normalization

(12 Months Ended April 30, 2008)

	(1)	(2)	(3)
	OAG Test Year Adjustment to kWh	Energy Rate	OAG Test Year Revenue Adjustment (1) * (2)
Residential	(35,909,380)	$0.05774	($2,073,408)
General Service Rate GS	(3,964,088)	0.06745	(267,378)
Large Power Rate LP			
Secondary	(5,989,830)	0.03282	(196,586)
Primary	(1,571,891)	0.03282	(51,589)
Transmission	-	0.03282	0
Secondary Small Time of Day	(355,666)	0.03879	(13,796)
Primary Small Time of Day	-	0.03879	0
Total	(7,917,387)		(261,972)
Large Power Rate LCTOD	-		0
Primary	-	0.03282	0
Transmission	-	0.03282	0
Large Mine Power TOD	-		0
Primary	-	0.03082	0
Transmission	-	0.03082	0
Street Lighting	-		0
Total Company	(48,146,521)		(2,602,757)
Variable Expenses	(48,146,521)	$0.02742	($1,320,178)

KENTUCKY UTILITIES

OAG Adjustment to Reflect Electric Weather Normalization

(12 Months Ended April 30, 2008)

Residential

	Degree Days			Normal Weather Band							
	Actual 1/	30-year Average 2/	30-year Std Dev 3/	Upper Limit	Lower Limit	Adjustment	Boundary Limit less Actual	kWh Per Customer Per Degree Day 4/	Average Customers	kWh Adjustment	Model R-square
Cooling Season (CDD)											
Cooling Month											
June	284	242									
July	309	361									
August	496	332									
September	238	151									
Seasonal Aggregate	1,327	1,085	188	1,273	897	Yes	-54	1.62464	412,293	(35,909,380)	86.41634%
Heating Season (HDD)											
Heating Month											
November	577	555									
December	765	883									
January	1,012	989									
February	849	801									
March	638	609									
Seasonal Aggregate	3,841	3,837	215	4,052	3,622	No	211				

1/ Per NOAA, National Climatic Data Center
2/ 30-year Average 1978 to 2007
3/ Standard deviation of Seasonal Degree Days.
4/ Linear regression model developed based on daily observations of kWh usage, degree days, and a binary variable for Weekdays and Holidays.

KENTUCKY UTILITIES

OAG Adjustment to Reflect Electric Weather Normalization

(12 Months Ended April 30, 2008)

General Service Secondary

	Degree Days			Normal Weather Band					
	Actual 1/	30-year Average 2/	30-year Std Dev 3/	Upper Limit	Lower Limit	Adjustment	Boundary Limit less Actual	kWh Per Degree Day 4/	kWh Adjustment
Cooling Season (CDD)									
Cooling Month									
June	284	242							
July	309	361							
August	496	332							
September	238	151							
Seasonal Aggregate	1,327	1,085	188	1,273	897	Yes	-54	73,943.08	-3,964,088
Heating Season (HDD)									
Heating Month									
November	577	555							
December	765	880							
January	1,012	1,001							
February	849	817							
March	638	615							
Seasonal Aggregate	3,483	3,615	215	3,830	3,400	No	347		

1/ Per NOAA, National Climatic Data Center
2/ 30-year Average 1978 to 2007
3/ Standard deviation of Seasonal Degree Days.
4/ Linear regression model developed based on daily observations of kWh usage, degree days, and a binary variable for Weekdays and Holidays.

KENTUCKY UTILITIES

OAG Adjustment to Reflect Electric Weather Normalization

(12 Months Ended April 30, 2008)

LP Secondary

	Degree Days			Normal Weather Band					
	Actual [1/]	30-year Average [2/]	30-year Std Dev [3/]	Upper Limit	Lower Limit	Adjustment	Boundary Limit less Actual	kWh Per Degree Day [4/]	kWh Adjustment
Cooling Season (CDD)									
Cooling Month									
June	284	242							
July	309	361							
August	496	332							
September	238	151							
Seasonal Aggregate	1,327	1,085	188	1,273	897	Yes	-54	83,596.81	-4,481,625
Heating Season (HDD)									
Heating Month									
November	577	555							
December	765	880							
January	1,012	1,001							
February	849	817							
March	638	615							
Seasonal Aggregate	3,483	3,615	215	3,830	3,400	No	347		

1/ Per NOAA, National Climatic Data Center
2/ 30-year Average 1978 to 2007
3/ Standard deviation of Seasonal Degree Days.
4/ Linear regression model developed based on daily observations of kWh usage, degree days, and a binary variable for Weekdays and Holidays.

KENTUCKY UTILITIES

OAG Adjustment to Reflect Electric Weather Normalization

(12 Months Ended April 30, 2008)

LP Secondary PF

	Degree Days			Normal Weather Band					
	Actual 1/	30-year Average 2/	30-year Std Dev 3/	Upper Limit	Lower Limit	Adjustment	Boundary Limit less Actual	kWh Per Degree Day 4/	kWh Adjustment
Cooling Season (CDD)									
Cooling Month									
June	284	242							
July	309	361							
August	496	332							
September	238	151							
Seasonal Aggregate	1,327	1,085	188	1,273	897	Yes	-54	28,132.91	-1,508,205
Heating Season (HDD)									
Heating Month									
November	577	555							
December	765	880							
January	1,012	1,001							
February	849	817							
March	638	615							
Seasonal Aggregate	3,483	3,615	215	3,830	3,400	No	347		

1/ Per NOAA, National Climatic Data Center
2/ 30-year Average 1978 to 2007
3/ Standard deviation of Seasonal Degree Days.
4/ Linear regression model developed based on daily observations of kWh usage, degree days, and a binary variable for Weekdays and Holidays.

KENTUCKY UTILITIES

OAG Adjustment to Reflect Electric Weather Normalization

(12 Months Ended April 30, 2008)

LP Primary

	Degree Days			Normal Weather Band					
	Actual 1/	30-year Average 2/	30-year Std Dev 3/	Upper Limit	Lower Limit	Adjustment	Boundary Limit less Actual	kWh Per Degree Day 4/	kWh Adjustment
Cooling Season (CDD)									
Cooling Month									
June	284	242							
July	309	361							
August	496	332							
September	238	151							
Seasonal Aggregate	1,327	1,085	188	1,273	897	Yes	-54	7,085.19	-379,837
Heating Season (HDD)									
Heating Month									
November	577	555							
December	765	880							
January	1,012	1,001							
February	849	817							
March	638	615							
Seasonal Aggregate	3,483	3,615	215	3,830	3,400	No	347		

1/ Per NOAA, National Climatic Data Center
2/ 30-year Average 1978 to 2007
3/ Standard deviation of Seasonal Degree Days.
4/ Linear regression model developed based on daily observations of kWh usage, degree days, and a binary variable for Weekdays and Holidays.

KENTUCKY UTILITIES

OAG Adjustment to Reflect Electric Weather Normalization

(12 Months Ended April 30, 2008)

LP Primary PF

	Degree Days			Normal Weather Band					
	Actual 1/	30-year Average 2/	30-year Std Dev 3/	Upper Limit	Lower Limit	Adjustment	Boundary Limit less Actual	kWh Per Degree Day 4/	kWh Adjustment
Cooling Season (CDD)									
Cooling Month									
June	284	242							
July	309	361							
August	496	332							
September	238	151							
Seasonal Aggregate	1,327	1,085	188	1,273	897	Yes	-54	22,235.66	-1,192,054
Heating Season (HDD)									
Heating Month									
November	577	555							
December	765	880							
January	1,012	1,001							
February	849	817							
March	638	615							
Seasonal Aggregate	3,483	3,615	215	3,830	3,400	No	347		

1/ Per NOAA, National Climatic Data Center
2/ 30-year Average 1978 to 2007
3/ Standard deviation of Seasonal Degree Days.
4/ Linear regression model developed based on daily observations of kWh usage, degree days, and a binary variable for Weekdays and Holidays.

KENTUCKY UTILITIES

OAG Adjustment to Reflect Electric Weather Normalization

(12 Months Ended April 30, 2008)

LP Secondary STOD

	Degree Days			Normal Weather Band					
	Actual 1/	30-year Average 2/	30-year Std Dev 3/	Upper Limit	Lower Limit	Adjustment	Boundary Limit less Actual	kWh Per Degree Day 4/	kWh Adjustment
Cooling Season (CDD)									
Cooling Month									
June	284	242							
July	309	361							
August	496	332							
September	238	151							
Seasonal Aggregate	1,327	1,085	188	1,273	897	Yes	-54	6,634.32	-355,666
Heating Season (HDD)									
Heating Month									
November	577	555							
December	765	880							
January	1,012	1,001							
February	849	817							
March	638	615							
Seasonal Aggregate	3,483	3,615	215	3,830	3,400	No	347		

1/ Per NOAA, National Climatic Data Center
2/ 30-year Average 1978 to 2007
3/ Standard deviation of Seasonal Degree Days.
4/ Linear regression model developed based on daily observations of kWh usage, degree days, and a binary variable for Weekdays and Holidays.

Eon Generation Unit Classification

Unit	Type	Gross Plant	Percent Energy	Demand	Gross Plant Energy	Gross Plant Demand
Trimble 1	Base	$598.442	100%	0%	$598.442	$0.000
Mill Creek 3	Base	$272.591	100%	0%	$272.591	$0.000
Mill Creek 4	Base	$494.022	100%	0%	$494.022	$0.000
Mill Creek 1	Base	$153.584	100%	0%	$153.584	$0.000
Mill Creek 2	Base	$121.972	100%	0%	$121.972	$0.000
Ghent 1	Base	$341.335	100%	0%	$341.335	$0.000
Cane Run 6	Base	$131.258	100%	0%	$131.258	$0.000
Ghent 4	Base	$365.800	100%	0%	$365.800	$0.000
Ghent 3	Base	$490.572	100%	0%	$490.572	$0.000
Cane Run 5	Base	$89.856	100%	0%	$89.856	$0.000
Cane Run 4	Base	$70.514	100%	0%	$70.514	$0.000
Brown 2	Base	$43.716	100%	0%	$43.716	$0.000
Brown 3	Base	$145.556	100%	0%	$145.556	$0.000
Brown 1	Base	$53.103	100%	0%	$53.103	$0.000
Ghent 2	Base	$148.052	100%	0%	$148.052	$0.000
Green River 4	Intermediate	$42.268	63%	37%	$26.629	$15.639
Tyrone 3	Intermediate	$24.555	69%	31%	$16.943	$7.612
Green River 3	Intermediate	$19.529	68%	32%	$13.280	$6.249
Trimble 5	Peak	$63.319	0%	100%	$0.000	$63.319
Trimble 6	Peak	$55.910	0%	100%	$0.000	$55.910
Trimble 7	Peak	$52.341	0%	100%	$0.000	$52.341
Trimble 8	Peak	$51.951	0%	100%	$0.000	$51.951
Trimble 9	Peak	$52.052	0%	100%	$0.000	$52.052
Trimble 10	Peak	$52.023	0%	100%	$0.000	$52.023
Brown 6	Peak	$58.868	0%	100%	$0.000	$58.868
Brown 7	Peak	$58.872	0%	100%	$0.000	$58.872
Brown 8	Peak	$35.458	0%	100%	$0.000	$35.458
Brown 9	Peak	$45.866	0%	100%	$0.000	$45.866
Brown 10	Peak	$28.591	0%	100%	$0.000	$28.591
Brown 11	Peak	$43.497	0%	100%	$0.000	$43.497
Brown 5	Peak	$45.189	0%	100%	$0.000	$45.189
Paddys Run 13	Peak	$64.098	0%	100%	$0.000	$64.098
Paddys Run 11	Peak	$1.826	0%	100%	$0.000	$1.826
Cane Run 11	Peak	$2.797	0%	100%	$0.000	$2.797
Paddys Run 12	Peak	$3.162	0%	100%	$0.000	$3.162
Zorn 1	Peak	$1.901	0%	100%	$0.000	$1.901
Haefling 1,2 & 3	Peak	$5.345	0%	100%	$0.000	$5.345
Ohio Falls 1- 8	Hydro	$29.739	100%	0%	$29.739	$0.000
Dix Dam 1,2, &3	Hydro	$11.033	100%	0%	$11.033	$0.000
Total		$4,370.563			$3,617.997	$752.566
Percent					82.78%	17.22%

Kentucky Utilities
Electric Cost of Service Study
(Summary)

	Total	Rate RS	GSS	GSP	AES	LPS	LPP	LPT	STODS	STODP
Total Operating Revenue	$1,154,156,041	$434,201,182	$141,196,389	$3,110,084	$7,940,212	$226,074,364	$86,951,352	$1,370,360	$9,536,117	$765,874
Pro-Forma Adjustments:										
Eliminate Unbilled Revenue	-$8,878,000	-$2,594,613	-$846,156	-$18,681	-$47,381	-$1,343,022	-$515,139	-$8,119	-$56,155	-$4,508
Mismatch in Fuel Cos Recovery	-$116,253,633	-$40,731,777	-$11,406,305	-$265,407	-$827,021	-$23,801,704	-$9,863,831	-$154,207	-$1,186,661	-$96,213
To Reflect a Full Year of the FAC Roll-	$98,267	$34,430	$9,642	$224	$699	$20,119	$8,338	$130	$1,003	$81
Remove ECR Revenue	-$54,342,557	-$20,626,185	-$6,655,772	-$150,005	-$375,764	-$10,481,263	-$4,017,702	-$63,714	-$439,539	-$35,499
To Reflect a full Year of the ECR Roll-	$21,935,653	$8,325,866	$2,686,637	$60,550	$151,679	$4,230,816	$1,621,766	$25,718	$177,422	$14,329
Remove Off-System ECR Revenues	-$371,295	-$105,791	-$37,805	-$93	-$2,090	-$83,324	-$35,459	-$493	-$4,186	-$340
Eliminate Brokered Sales	$90,748	$31,795	$8,904	$207	$646	$18,580	$7,700	$120	$926	$75
Eliminate Rate Refund Acct	$17,682,129	$6,670,295	$2,175,319	$48,026	$121,809	$3,452,674	$1,324,332	$20,872	$144,364	$11,568
Eliminate DSM Revenue	-$4,429,150	-$3,999,569	-$123,092	-$2,670	$0	-$240,135	-$45,915	-$2,128	-$15,427	-$215
Year End Revenue Adjustment	-$4,243,045	$843,080	$1,130,682	-$40,127	$0	-$6,373,654	$0	$0	$0	$0
Adjustment for Merger Surecredit	$18,568,431	$7,355,580	$2,396,449	$53,506	$132,776	$3,766,072	$1,337,070	$22,850	$158,833	$12,665
Weather Normalized Electric Operating Revenues	-$8,721,229	-$3,055,656	-$855,689	-$19,911	-$62,042	-$1,785,580	-$739,975	-$11,568	-$89,022	-$7,218
VDT Surecredit Revenues	$3,405,550	$1,281,116	$416,427	$9,403	$23,364	$660,193	$253,206	$3,988	$27,621	$2,222
Sub-Total	-$133,458,131	-$46,571,429	-$11,100,781	-$324,977	-$883,323	-$31,960,228	-$10,665,610	-$166,550	-$1,280,821	-$103,031
Total Pro-Forma Operating Revenue	$1,020,697,910	$387,629,753	$130,095,608	$2,785,088	$7,056,889	$194,114,135	$76,285,742	$1,203,810	$8,255,296	$662,844
Operating Expenses										
Operation and Maintenance Expenses	$789,501,237	$304,616,034	$83,213,642	$1,838,353	$5,300,608	$152,455,062	$60,694,046	$926,273	$7,353,503	$587,344
Depreciation and Amortization Expenses	$109,736,123	$46,776,559	$13,144,361	$293,559	$730,284	$18,873,622	$7,037,078	$101,167	$882,131	$65,691
Regulatory Credits & Accretion Expense	-$255,374	-$92,408	-$25,620	-$751	-$1,803	-$51,679	-$21,112	-$339	-$2,576	-$201
Property and Other Taxes	$17,237,030	$7,353,896	$2,066,602	$46,085	$114,671	$2,961,609	$1,103,529	$15,851	$138,360	$10,300
Gain on Disposition of Allowance	-$504,602	-$208,908	-$58,544	-$1,367	-$3,393	-$89,744	-$34,153	-$504	-$4,253	-$320
State and Federal Income Taxes	$56,064,862	$16,146,262	$11,179,252	$240,557	$437,463	$12,900,018	$4,420,364	$83,612	$213,855	$20,725
Specific Assignment of Interruptible Credit	-$2,040,216						$430,293			
Allocation of Interruptible Credits	$2,040,216	$985,796	$184,843	$13,076	$20,687	$336,251	$128,995	$2,705	$16,413	$1,328
Adjustments to Operating Expenses:										
Eliminate mismatch in fuel cost recovery	-$96,155,056	-$33,689,840	-$9,434,319	-$219,522	-$684,041	-$19,686,733	-$8,158,517	-$127,547	-$981,505	-$79,579
Remove ECR expenses	-$16,467,656	-$6,250,440	-$2,016,927	-$45,457	-$113,869	-$3,176,182	-$1,217,501	-$19,307	-$133,195	-$10,757
Reflect full year of ECR roll-in	$8,506,554	$3,228,736	$1,041,866	$23,481	$58,821	$1,640,693	$628,914	$9,973	$68,804	$5,557
Eliminate brokered sales expenses	-$8,127	-$2,847	-$797	-$19	-$58	-$1,664	-$690	-$11	-$83	-$7
Eliminate DSM Expenses	-$4,437,148	-$4,006,791	-$123,314	-$2,674	$0	-$240,569	-$45,997	-$2,132	-$15,455	-$215
Year end Expense adjustment	-$2,747,550	$545,930	$732,151	-$25,984	$0	-$4,127,209	$0	$0	$0	$0
Depreciation adjustment	$238,248	$100,704	$28,298	$632	$1,572	$40,633	$15,150	$218	$1,899	$141
Labor adjustment	$1,549,969	$740,732	$196,078	$3,776	$8,793	$254,255	$85,887	$1,160	$10,694	$805
Weather Normalization Expenses	-$4,355,146	-$1,525,912	-$427,308	-$9,943	-$30,982	-$891,670	-$369,523	-$5,777	-$44,455	-$3,604
Storm damage adjustment	-$2,731,370	-$1,869,618	-$442,802	-$3,448	-$10,999	-$218,611	-$36,332	-$4	-$5,928	-$291
Amortization of rate case expenses	$324,904	$128,137	$34,817	$755	$2,149	$61,817	$24,350	$369	$2,955	$235
Amortization of ESM audit expenses	-$37,986	-$14,330	-$4,673	-$103	-$262	-$7,417	-$2,845	-$45	-$310	-$25
Adjustment for EKPC settlement charges	-$1,338,790	-$469,072	-$131,356	-$3,056	-$9,524	-$274,103	-$113,593	-$1,776	-$13,666	-$1,108
Adjustment for MISO schedule 10 expenses	$1,961,979	$709,658	$196,747	$5,770	$13,855	$397,177	$162,284	$2,604	$19,801	$1,541
Adjustment to reflect reallocation of OVEC Demand Charges	$2,721,857	$953,657	$267,057	$6,214	$19,363	$557,271	$230,943	$3,610	$27,783	$2,253
Adjustment for Reserve Margin Demand Purchases	$1,199,403	$499,185	$132,753	$7,320	$8,170	$229,529	$86,909	$1,597	$11,440	$700
Adjustment for new credit facilities bank fees	$2,005,628	$830,342	$232,692	$5,435	$13,486	$356,705	$135,746	$2,004	$16,903	$1,273
Adjustment to reflect annualized vehicle fuel costs	$198,608	$74,922	$24,433	$539	$1,368	$38,781	$14,875	$234	$1,622	$130
Adjustment for Tyrone retirement	-$9,585	-$3,467	-$961	-$28	-$68	-$1,940	-$793	-$13	-$97	-$8
Expense Adjustments	-$109,583,264	-$40,020,315	-$9,695,566	-$256,311	-$722,225	-$25,049,237	-$8,560,733	-$134,840	-$1,032,795	-$82,957
Operating Expenses	$862,196,011	$335,556,915	$100,008,971	$2,173,200	$5,876,270	$162,335,901	$65,198,308	$993,925	$7,564,638	$601,910
rating Income -- Pro-Forma	$158,501,899	$52,072,837	$30,086,637	$611,887	$1,180,619	$31,778,235	$11,087,434	$209,886	$690,658	$60,933
Net Cost Rate Base	$2,634,973,710	$1,090,894,641	$305,708,873	$7,140,789	$17,717,717	$468,634,814	$178,341,854	$2,632,364	$22,206,711	$1,672,966
Less: ECR Rate Base	$415,886,486	$118,496,647	$42,345,211	$103,900	$2,340,527	$93,330,868	$39,717,814	$551,821	$4,688,442	$380,401
Adjustment to Reflect Depreciation Reserve	-$238,248	-$100,704	-$28,298	-$632	-$1,572	-$40,633	-$15,150	-$218	-$1,899	-$141
Cash Working Capital	-$1,942,732	-$766,182	-$208,184	-$4,515	-$12,852	-$369,631	-$145,598	-$2,205	-$17,668	-$1,407
Adjusted Net Cost Rate Base	$2,216,908,244	$971,531,108	$263,127,180	$7,031,742	$15,362,765	$374,893,682	$138,463,292	$2,078,119	$17,498,701	$1,291,016
RoR	7.15%	5.36%	11.43%	8.70%	7.68%	8.48%	8.01%	10.10%	3.95%	4.72%

Kentucky Utilities
Electric Cost of Service Study
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	LCIP	LCIT	MPP	MPT	LMPP	LMPT	LITOD	SL	SLDEC	POL	OL
Total Operating Revenue	$135,173,608	$35,809,536	$6,896,875	$3,993,096	$4,916,425	$13,992,126	$23,247,719	$7,371,816	$1,376,780	$4,131,161	$6,100,984
Pro-Forma Adjustments:											
Eliminate Unbilled Revenue	-$801,974	-$210,613	-$41,101	-$23,857	-$29,294	-$82,773	-$138,490	-$45,208	-$8,521	-$25,204	-$37,190
Mismatch in Fuel Cos Recovery	-$16,677,277	-$4,974,499	-$667,494	-$408,130	-$529,064	-$1,584,982	-$2,296,749	-$262,670	-$22,072	-$196,691	-$300,880
To Reflect a Full Year of the FAC Roll-	$14,097	$4,205	$564	$345	$447	$1,340	$1,941	$222	$19	$166	$254
Remove ECR Revenue	-$6,234,270	-$1,899,807	-$322,310	-$185,614	-$226,786	-$653,519	-$1,074,407	-$351,687	-$62,947	-$196,492	-$289,276
To Reflect a full Year of the ECR Roll-	$2,516,495	$766,867	$130,102	$74,924	$91,543	$263,796	$433,690	$141,960	$25,409	$79,315	$116,768
Remove Off-System ECR Revenues	-$60,397	-$18,230	-$1,949	-$1,260	-$1,750	-$5,645	-$8,956	-$1,185	-$100	-$888	-$1,358
Eliminate Brokered Sales	$13,018	$3,883	$521	$319	$413	$1,237	$1,793	$205	$17	$154	$235
Eliminate Rate Refund Acct	$2,061,735	$541,449	$105,663	$61,332	$75,310	$212,795	$356,034	$116,222	$21,906	$64,794	$95,609
Eliminate DSM Revenue	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Year End Revenue Adjustment	$0	$0	$215,149	$0	$0	$0	$0	$5,438	-$87,075	$65,957	-$2,475
Adjustment for Merger Surecredit	$1,629,902	$488,942	$115,118	$67,819	$82,168	$232,283	$388,337	$127,483	$24,581	$70,952	$105,042
Weather Normalized Electric Operating Revenues	-$1,251,112	-$373,182	-$50,075	-$30,617	-$39,690	-$118,904	-$172,300	-$19,705	-$1,656	-$14,756	-$22,572
VDT Surecredit Revenues	$394,429	$120,177	$20,228	$11,701	$14,392	$40,804	$68,105	$22,193	$4,259	$12,408	$19,315
Sub-Total	-$18,395,354	-$5,550,808	-$495,583	-$433,039	-$562,310	-$1,693,567	-$2,441,001	-$266,732	-$106,179	-$140,283	-$316,526
Total Pro-Forma Operating Revenue	$116,778,254	$30,258,728	$6,401,293	$3,560,058	$4,354,116	$12,298,559	$20,806,718	$7,105,084	$1,270,601	$3,990,878	$5,784,458
Operating Expenses											
Operation and Maintenance Expenses	$101,902,063	$29,650,637	$4,207,571	$2,462,928	$3,284,104	$9,489,990	$14,362,039	$2,754,499	$305,283	$1,714,789	$2,382,470
Depreciation and Amortization Expenses	$11,644,544	$3,100,490	$531,586	$274,858	$394,525	$1,018,632	$1,750,492	$1,729,255	$305,989	$475,507	$605,794
Regulatory Credits & Accretion Expense	-$35,332	-$10,388	-$1,502	-$920	-$1,132	-$3,412	-$4,765	-$486	-$42	-$359	-$549
Property and Other Taxes	$1,825,902	$485,788	$83,397	$43,065	$61,888	$159,600	$274,694	$272,997	$48,324	$74,981	$95,490
Gain on Disposition of Allowance	-$56,676	-$15,474	-$2,541	-$1,368	-$1,895	-$5,079	-$8,314	-$6,568	-$1,144	-$1,900	-$2,456
State and Federal Income Taxes	$4,177,582	$268,913	$552,378	$326,787	$297,786	$851,208	$1,829,905	$581,598	$181,825	$509,669	$845,103
Specific Assignment of Interruptible Credit	-$644,684	-$1,192,286					-$633,539				
Allocation of Interruptible Credits	$213,147	$61,185	$13,758	$7,652	$8,618	$21,319	$22,241	$746	$63	$559	$854
Adjustments to Operating Expenses:											
Eliminate mismatch in fuel cost recovery	-$13,794,017	-$4,114,480	-$552,094	-$337,570	-$437,597	-$1,310,962	-$1,899,674	-$217,258	-$18,256	-$162,686	-$248,862
Remove ECR expenses	-$1,889,197	-$575,707	-$97,671	-$56,247	-$68,724	-$198,039	-$325,582	-$106,573	-$19,075	-$59,544	-$87,660
Reflect full year of ECR roll-in	$975,886	$297,388	$50,453	$29,055	$35,500	$102,299	$168,183	$55,052	$9,853	$30,758	$45,282
Eliminate brokered sales expenses	-$1,166	-$348	-$47	-$29	-$37	-$111	-$161	-$18	-$2	-$14	-$21
Eliminate DSM Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Year end Expense adjustment	$0	$0	$139,318	$0	$0	$0	$0	$3,521	-$56,385	$42,710	-$1,603
Depreciation adjustment	$25,069	$6,675	$1,144	$592	$849	$2,193	$3,769	$3,723	$659	$1,024	$1,304
Labor adjustment	$139,831	$36,053	$6,535	$3,143	$4,826	$11,742	$21,876	$10,657	$1,432	$5,449	$6,245
Weather Normalization Expenses	-$624,772	-$186,357	-$25,006	-$15,290	-$19,820	-$59,377	-$86,042	-$9,840	-$827	-$7,369	-$11,272
Storm damage adjustment	-$54,058	-$12	-$4,111	-$21	-$2,788	-$11	-$16,154	-$22,633	-$2,614	-$22,534	-$18,402
Amortization of rate case expenses	$40,812	$11,795	$1,697	$981	$1,321	$3,777	$5,792	$1,236	$142	$747	$1,019
Amortization of ESM audit expenses	-$4,429	-$1,163	-$227	-$132	-$162	-$457	-$765	-$250	-$47	-$139	-$205
Adjustment for EKPC settlement charges	-$192,057	-$57,287	-$7,687	-$4,700	-$6,093	-$18,253	-$26,450	-$3,025	-$254	-$2,265	-$3,465
Adjustment for MISO schedule 10 expenses	$271,593	$79,851	$11,544	$7,072	$8,701	$26,232	$36,619	$3,670	$308	$2,748	$4,203
Adjustment to reflect reallocation of OVEC Demand Charges	$390,467	$116,468	$15,628	$9,556	$12,387	$37,109	$53,774	$6,150	$517	$4,605	$7,045
Adjustment for Reserve Margin Demand Purchases	$137,042	$36,761	$7,878	$4,864	$4,650	$14,516	$16,089	$0	$0	$0	$0
Adjustment for new credit facilities bank fees	$225,268	$61,504	$10,100	$5,439	$7,531	$20,188	$33,045	$26,106	$4,546	$7,553	$9,763
Adjustment to reflect annualized vehicle fuel costs	$23,158	$6,082	$1,187	$689	$846	$2,390	$3,999	$1,305	$246	$728	$1,074
Adjustment for Tyrone retirement	-$1,327	-$390	-$56	-$35	-$43	-$128	-$179	-$18	-$2	-$13	-$21
Expense Adjustments	-$14,331,897	-$4,283,166	-$441,414	-$352,633	-$458,651	-$1,366,891	-$2,011,861	-$248,196	-$79,758	-$158,242	-$295,576
Operating Expenses	$104,694,650	$28,065,701	$4,943,234	$2,760,368	$3,585,243	$10,165,368	$15,580,893	$5,083,845	$760,540	$2,615,003	$3,631,130
rating Income -- Pro-Forma	$12,083,604	$2,193,027	$1,458,059	$799,689	$768,873	$2,133,191	$5,225,825	$2,021,239	$510,062	$1,375,875	$2,153,328
Net Cost Rate Base	$295,955,020	$80,803,283	$13,269,079	$7,145,932	$9,894,085	$26,522,617	$43,414,754	$34,297,253	$5,972,091	$9,922,639	$12,826,229
Less: ECR Rate Base	$67,650,270	$20,419,031	$2,182,601	$1,410,919	$1,959,661	$6,322,755	$10,031,079	$1,327,780	$111,571	$994,259	$1,520,927
Adjustment to Reflect Depreciation Reserve	-$25,069	-$6,675	-$1,144	-$592	-$849	-$2,193	-$3,769	-$3,723	-$659	-$1,024	-$1,304
Cash Working Capital	-$244,033	-$70,529	-$10,148	-$5,867	-$7,898	-$22,585	-$34,635	-$7,390	-$846	-$4,465	-$6,091
Adjusted Net Cost Rate Base	$228,035,647	$60,307,047	$11,075,186	$5,728,553	$7,925,677	$20,175,084	$33,345,271	$32,958,360	$5,859,013	$8,922,891	$11,297,907
RoR	5.30%	3.64%	13.17%	13.96%	9.70%	10.57%	15.67%	6.13%	8.71%	15.42%	19.06%

Kentucky Utilities
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(Rate Base)

			Total	Rate RS	GSS	GSP	AES	LPS	LPP	LPT	STODS	STODP
	RATE BASE											
	Plant-in-Service											
	Intangible Plant											
301.00	ORGANIZATION	PT&D	$38,811	$16,558	$4,653	$104	$258	$6,668	$2,485	$36	$312	$23
302.00	FRANCHISE AND CONSENTS	PT&D	$83,453	$35,604	$10,005	$223	$555	$14,339	$5,343	$77	$670	$50
303.00	SOFTWARE	PT&D	$22,294,019	$9,511,378	$2,672,901	$59,606	$146,313	$3,830,484	$1,427,282	$20,501	$178,952	$13,322
	Sub-total		$22,416,283	$9,563,540	$2,687,560	$59,932	$149,126	$3,851,491	$1,435,110	$20,614	$179,933	$13,395
	Production Plant											
	Steam Production Generation	$1,434,800,591										
330	Hydro Baseload Generation	$9,546,697										
340	Other Production Generation	$428,799,376										
	Total Production	$1,873,146,664										
	Energy Related		$1,550,590,809	$543,280,385	$152,137,280	$3,539,999	$11,030,799	$317,467,101	$131,563,764	$2,056,811	$15,827,689	$1,283,286
	Demand Related		$322,555,858	$134,246,074	$35,701,266	$1,968,605	$2,197,241	$61,727,413	$23,372,584	$429,560	$3,076,488	$188,244
	Total Production Plant		$1,873,146,664	$677,526,459	$187,838,546	$5,508,604	$13,228,040	$379,194,514	$154,936,348	$2,486,371	$18,904,177	$1,471,531
	Transmission Plant											
	KENTUCKY SYSTEM PROPERTY		$410,409,382	$148,447,113	$41,155,721	$1,206,944	$2,898,284	$83,082,115	$33,946,798	$544,768	$4,141,935	$322,415
	VIRGINIA PROPERTY - 500 KV LINE		$7,475,857	$2,704,055	$749,677	$21,985	$52,794	$1,513,391	$618,362	$9,923	$75,448	$5,873
	Total Transmission Plant		$417,885,239	$151,151,168	$41,905,397	$1,228,929	$2,951,078	$84,595,506	$34,565,159	$554,691	$4,217,383	$328,288
	Distribution Plant											
360-362	TOTAL ACCTS 360-362		$102,616,477	$52,269,797	$10,767,237	$602,883	$1,080,951	$16,511,923	$6,485,042	$0	$720,711	$51,755
364-365	OVERHEAD LINES	383,731,335										
	Primary	312,674,484										
	Customer		$122,881,072	$96,871,453	$18,412,257	$16,830	$72,463	$2,035,287	$81,112	$468	$11,921	$468
	Demand		$189,793,412	$96,675,148	$19,914,450	$1,115,057	$1,999,264	$30,539,483	$11,994,354	$0	$1,332,984	$95,723
	Secondary	71,056,850										
	Customer		$27,925,342	$22,036,365	$4,188,429	$0	$16,484	$462,988	$0	$0	$2,712	$106
	Demand		$43,131,508	$26,240,535	$13,230,190	$0	$264,408	$3,164,048	$0	$0	$177,560	$0
366-367	UNDERGROUND LINES	86,588,726										
	Primary	70,554,794										
	Customer		$14,181,514	$11,179,784	$2,124,930	$1,942	$8,363	$234,889	$9,361	$54	$1,376	$54
	Demand		$56,373,280	$28,714,881	$5,915,078	$331,199	$593,830	$9,070,973	$3,562,616	$0	$395,929	$28,432
	Secondary	16,033,932										
	Customer		$3,222,820	$2,543,183	$483,380	$0	$1,902	$53,433	$0	$0	$313	$12
	Demand		$12,811,112	$7,794,080	$3,929,690	$0	$78,536	$945,740	$0	$0	$52,740	$0
368	TRANSFORMERS - POWER POOL	5,372,853										
	Customer		$1,421,119	$1,121,430	$213,149	$0	$839	$23,561	$0	$0	$138	$5
	Demand		$3,951,733	$2,404,173	$1,212,157	$0	$24,225	$291,724	$0	$0	$16,268	$0
368	TRANSFORMERS - ALL OTHER	230,038,518										
	Customer		$60,845,188	$48,013,979	$9,125,967	$0	$35,916	$1,008,783	$0	$0	$5,909	$232
	Demand		$169,193,330	$102,934,576	$51,898,486	$0	$1,037,203	$12,490,167	$0	$0	$696,521	$0
369	SERVICES		$78,030,101	$45,879,905	$8,653,850	$0	$487,376	$23,001,011	$0	$0	$7,959	$0
370	METERS		$61,476,425	$38,269,497	$16,884,059	$40,882	$130,884	$4,855,300	$195,373	$1,107	$14,447	$553
371	CUSTOMER INSTALLATION		$17,415,370	$0	$0	$0	$0	$0	$0	$0	$0	$0
373	STREET LIGHTING		$52,453,968	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Total Distribution Plant		$1,017,723,772	$582,948,784	$166,953,311	$2,108,793	$5,832,645	$104,709,311	$22,327,858	$1,628	$3,437,488	$177,340
	General Plant											
	Total General Plant		$88,658,922	$37,824,877	$10,629,600	$237,039	$589,811	$15,233,079	$5,676,020	$81,530	$711,656	$52,978
	TOTAL COMMON PLANT		$0									
106	COMPLETED CONSTR NOT CLASSIFIED		$0									
105	PLANT HELD FOR FUTURE USE		$0									
	OTHER		$0									
	Total General Plant		$88,658,922	$37,824,877	$10,629,600	$237,039	$589,811	$15,233,079	$5,676,020	$81,530	$711,656	$52,978
	Construction Work In Progress											
	CWIP Production		$850,877,946	$307,766,783	$85,325,767	$2,502,287	$6,008,845	$172,249,326	$70,379,925	$1,129,435	$8,587,233	$668,444
	CWIP Transmission		$59,963,820	$21,689,212	$6,013,153	$176,343	$423,461	$12,138,906	$4,959,876	$79,595	$605,167	$47,107
	CWIP Distribution Plant		$137,343,542	$78,669,923	$22,530,631	$284,585	$787,125	$14,130,698	$3,013,182	$220	$463,895	$23,932
	CWIP General Plant		$27,677,464	$11,808,137	$3,318,339	$73,999	$184,127	$4,755,449	$1,771,935	$25,452	$222,184	$16,539

Kentucky Utilities
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	Total	Rate RS	GSS	GSP	AES	LPS	LPP	LPT	STODS	STODP
RWIP	$0									
Total CWIP	$1,075,862,772	$419,934,054	$117,187,890	$3,037,214	$7,403,557	$203,274,380	$80,124,918	$1,234,701	$9,878,459	$756,022
TOTAL PLANT-IN-SERVICE	$3,419,830,880	$1,459,014,829	$410,014,415	$9,143,298	$22,750,700	$587,583,902	$218,940,495	$3,144,833	$27,450,637	$2,043,531
TOTAL UTILITY PLANT	$4,495,693,652	$1,878,948,883	$527,202,305	$12,180,512	$30,154,258	$790,858,282	$299,065,414	$4,379,534	$37,329,097	$2,799,553
Accumulated Reserve for Depreciation										
Steam Production	$801,561,442	$289,928,758	$80,380,324	$2,357,255	$5,660,575	$162,265,832	$66,300,736	$1,063,974	$8,089,521	$629,701
Hydraulic Production	$7,152,933	$2,587,251	$717,294	$21,036	$50,514	$1,448,020	$591,651	$9,495	$72,189	$5,619
Other Production	$105,179,005	$38,043,769	$10,547,317	$309,313	$742,767	$21,292,140	$8,699,826	$139,612	$1,061,488	$82,628
Transmission - Kentucky System Property	$254,442,507	$92,033,120	$25,515,413	$748,272	$1,796,856	$51,508,622	$21,046,079	$337,741	$2,567,886	$199,888
Transmission - Virginia Property	$4,333,686	$1,567,516	$434,581	$12,745	$30,604	$877,299	$358,459	$5,752	$43,736	$3,405
Distribution	$474,165,401	$271,600,361	$77,784,843	$982,503	$2,717,475	$48,784,881	$10,402,722	$759	$1,601,552	$82,624
General Plant	$44,717,082	$19,077,811	$5,361,273	$119,556	$297,484	$7,683,139	$2,882,826	$41,121	$358,940	$26,721
Intangible Plant	$16,103,542	$6,870,312	$1,930,705	$43,055	$107,130	$2,766,857	$1,030,962	$14,809	$129,262	$9,623
TOTAL ACCUMULATED RESERVE FOR DEPRECIATION	$1,707,655,598	$721,708,898	$202,671,749	$4,593,735	$11,403,405	$296,626,789	$111,293,262	$1,613,262	$13,924,673	$1,040,208
Rate Base Adjustments and Working Capital										
Working Capital Assets										
Cash Working Capital - Operation and Maintenance Expenses	$78,937,746	$31,131,770	$8,459,008	$183,465	$522,221	$15,018,892	$5,915,870	$89,603	$717,912	$57,162
Materials and Supplies	$74,430,157	$31,754,407	$8,923,669	$198,997	$495,153	$12,788,341	$4,765,082	$68,445	$597,443	$44,476
Prepayments	$1,461,220	$623,405	$175,190	$3,907	$9,721	$251,062	$93,549	$1,344	$11,729	$873
Sub-total	$154,829,123	$63,509,583	$17,557,867	$386,369	$1,027,095	$28,058,395	$10,774,600	$159,392	$1,327,085	$102,511
Other Rate Base Items										
Deferred Debits										
Total Production Plant	$143,326,414	$51,841,877	$14,372,727	$421,498	$1,012,162	$29,014,594	$11,855,170	$190,248	$1,446,479	$112,598
Total Transmission Plant	$24,426,563	$8,835,209	$2,449,488	$71,834	$172,499	$4,944,844	$2,020,430	$32,423	$246,518	$19,169
Total Distribution Plant	$82,470,281	$47,238,702	$13,528,903	$170,884	$472,643	$8,485,020	$1,809,317	$132	$278,554	$14,371
Total General Plant	$6,674,350	$2,847,502	$800,209	$17,845	$44,402	$1,146,765	$427,298	$6,138	$53,574	$3,988
Sub-total	$256,897,609	$110,763,290	$31,151,327	$682,061	$1,701,705	$43,591,223	$16,112,214	$228,941	$2,025,125	$150,144
Accumulated Deferred Investment Tax Credits										
Production	$48,588,068	$17,574,546	$4,872,396	$142,889	$343,126	$9,836,031	$4,018,937	$64,495	$490,361	$38,170
Transmission	$74,169	$26,827	$7,438	$218	$524	$15,014	$6,135	$98	$749	$58
Transmission VA	$3,355	$1,213	$336	$10	$24	$679	$277	$4	$34	$3
Distribution VA	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Distribution Plant KY,FERC & TN	$101,221	$57,979	$16,605	$210	$580	$10,414	$2,221	$0	$342	$18
General	$16,235	$6,926	$1,946	$43	$108	$2,789	$1,039	$15	$130	$10
Sub-total	$48,783,047	$17,667,492	$4,898,721	$143,370	$344,361	$9,864,928	$4,028,609	$64,613	$491,615	$38,259
Customer Advances										
Customer Advances	$2,405,862	$1,493,972	$348,860	$7,494	$15,526	$238,002	$80,042	$3	$10,106	$638
Sub-total	$2,405,862	$1,493,972	$348,860	$7,494	$15,526	$238,002	$80,042	$3	$10,106	$638
Emission Allowance										
Emission Allowance	$193,051	$69,828	$19,359	$568	$1,363	$39,081	$15,968	$256	$1,948	$152
Sub-total	$193,051	$69,828	$19,359	$568	$1,363	$39,081	$15,968	$256	$1,948	$152
TOTAL OTHER RATE BASE	$303,274,794	$128,936,809	$35,701,188	$817,938	$2,030,540	$53,218,149	$20,060,781	$293,551	$2,506,635	$187,765
TOTAL RATE BASE	$2,634,973,710	$1,090,894,641	$305,708,873	$7,140,789	$17,717,717	$468,634,814	$178,341,854	$2,632,364	$22,206,711	$1,672,966

Kentucky Utilities
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		LCIP	LCIT	MPP	MPT	LMPP	LMPT	LITOD	SL	SLDEC	POL	OL
RATE BASE												
Plant-In-Service												
Intangible Plant												
301.00 ORGANIZATION	PT&D	$4,111	$1,094	$188	$97	$139	$359	$619	$615	$109	$169	$215
302.00 FRANCHISE AND CONSENTS	PT&D	$8,840	$2,352	$404	$209	$300	$773	$1,330	$1,322	$234	$363	$462
303.00 SOFTWARE	PT&D	$2,361,584	$628,308	$107,864	$55,700	$80,045	$206,424	$355,284	$353,089	$62,501	$96,978	$123,504
Sub-total		$2,374,535	$631,754	$108,456	$56,005	$80,484	$207,556	$357,233	$355,025	$62,843	$97,510	$124,182
Production Plant												
Steam Production Generation	$1,434,800,591											
330 Hydro Baseload Generation	$9,546,697											
340 Other Production Generation	$428,799,376											
Total Production	$1,873,146,664											
Energy Related		$222,441,504	$66,349,867	$8,903,030	$5,443,637	$7,056,659	$21,140,491	$30,634,031	$3,503,492	$294,392	$2,623,459	$4,013,131
Demand Related		$36,854,681	$9,886,133	$2,118,677	$1,308,093	$1,250,395	$3,903,686	$4,326,714	$0	$0	$0	$0
Total Production Plant		$259,296,185	$76,236,001	$11,021,707	$6,751,731	$8,307,055	$25,044,177	$34,960,746	$3,503,492	$294,392	$2,623,459	$4,013,131
Transmission Plant												
KENTUCKY SYSTEM PROPERTY		$56,812,202	$16,703,428	$2,414,873	$1,479,315	$1,820,089	$5,487,219	$7,659,954	$767,621	$64,502	$574,804	$879,283
VIRGINIA PROPERTY - 500 KV LINE		$1,034,869	$304,263	$43,988	$26,947	$33,154	$99,953	$139,531	$13,983	$1,175	$10,470	$16,017
Total Transmission Plant		$57,847,071	$17,007,691	$2,458,862	$1,506,261	$1,853,243	$5,587,172	$7,799,485	$781,603	$65,677	$585,274	$895,300
Distribution Plant												
360-362 TOTAL ACCTS 360-362		$9,802,396	$0	$736,478	$0	$505,177	$0	$2,932,830	$50,128	$4,212	$37,536	$57,420
364-365 OVERHEAD LINES	383,731,335											
Primary	312,674,484											
Customer		$9,350	$1,636	$7,246	$2,805	$701	$1,403	$234	$1,832,026	$212,611	$1,832,026	$1,478,773
Demand		$18,129,936	$0	$1,362,147	$0	$934,345	$0	$5,424,391	$92,714	$7,791	$69,425	$106,200
Secondary	71,056,850											
Customer		$0	$0	$0	$0	$0	$0	$0	$416,750	$48,365	$416,750	$336,392
Demand		$0	$0	$0	$0	$0	$0	$0	$11,673	$981	$8,741	$13,371
366-367 UNDERGROUND LINES	86,588,726											
Primary	70,554,794											
Customer		$1,079	$189	$836	$324	$81	$162	$27	$211,431	$24,537	$211,431	$170,663
Demand		$5,385,034	$0	$404,591	$0	$277,523	$0	$1,611,177	$27,538	$2,314	$20,621	$31,544
Secondary	16,033,932											
Customer		$0	$0	$0	$0	$0	$0	$0	$48,096	$5,582	$48,096	$38,822
Demand		$0	$0	$0	$0	$0	$0	$0	$3,467	$291	$2,596	$3,972
368 TRANSFORMERS - POWER POOL	5,372,853											
Customer		$0	$0	$0	$0	$0	$0	$0	$21,208	$2,461	$21,208	$17,119
Demand		$0	$0	$0	$0	$0	$0	$0	$1,069	$90	$801	$1,225
368 TRANSFORMERS - ALL OTHER	230,038,518											
Customer		$0	$0	$0	$0	$0	$0	$0	$908,037	$105,380	$908,037	$732,949
Demand		$0	$0	$0	$0	$0	$0	$0	$45,790	$3,848	$34,288	$52,451
369 SERVICES		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
370 METERS		$22,255	$4,488	$16,783	$5,533	$1,660	$3,381	$430	$491,936	$0	$537,859	$0
371 CUSTOMER INSTALLATION		$0	$0	$0	$0	$0	$0	$0	$10,956,432	$2,118,048	$1,753,482	$2,587,408
373 STREET LIGHTING		$0	$0	$0	$0	$0	$0	$0	$33,000,064	$6,379,424	$5,281,374	$7,793,106
Total Distribution Plant		$33,350,049	$6,313	$2,528,081	$8,662	$1,719,488	$4,946	$9,969,089	$48,118,361	$8,915,935	$11,184,273	$13,421,416
General Plant												
Total General Plant		$9,391,554	$2,498,657	$428,956	$221,507	$318,322	$820,907	$1,412,895	$1,404,163	$248,553	$385,664	$491,153
TOTAL COMMON PLANT												
106 COMPLETED CONSTR NOT CLASSIFIED												
105 PLANT HELD FOR FUTURE USE												
OTHER												
Total General Plant		$9,391,554	$2,498,657	$428,956	$221,507	$318,322	$820,907	$1,412,895	$1,404,163	$248,553	$385,664	$491,153
Construction Work In Progress												
CWIP Production		$117,785,441	$34,630,247	$5,006,617	$3,066,978	$3,773,484	$11,376,332	$15,880,939	$1,591,463	$133,728	$1,191,708	$1,822,967
CWIP Transmission		$8,300,679	$2,440,493	$352,831	$216,139	$265,928	$801,723	$1,119,175	$112,155	$9,424	$83,983	$128,470
CWIP Distribution Plant		$4,500,645	$852	$341,169	$1,169	$232,048	$667	$1,345,345	$6,493,654	$1,203,220	$1,509,337	$1,811,243
CWIP General Plant		$2,931,847	$780,028	$133,911	$69,150	$99,373	$256,270	$441,076	$438,351	$77,593	$120,396	$153,328

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	LCIP	LCIT	MPP	MPT	LMPP	LMPT	LITOD	SL	SLDEC	POL	OL
RWIP											
Total CWIP	$133,518,613	$37,851,621	$5,834,527	$3,353,435	$4,370,834	$12,434,992	$18,786,536	$8,635,623	$1,423,965	$2,905,424	$3,916,007
TOTAL PLANT-IN-SERVICE	$362,259,395	$96,380,415	$16,546,062	$8,544,166	$12,278,591	$31,664,758	$54,499,447	$54,162,644	$9,587,400	$14,876,181	$18,945,181
TOTAL UTILITY PLANT	$495,778,008	$134,232,035	$22,380,590	$11,897,601	$16,649,424	$44,099,750	$73,285,983	$62,798,267	$11,011,365	$17,781,605	$22,861,188
Accumulated Reserve for Depreciation											
Steam Production	$110,958,650	$32,623,093	$4,716,436	$2,889,217	$3,554,775	$10,716,965	$14,960,487	$1,499,223	$125,977	$1,122,637	$1,717,309
Hydraulic Production	$990,167	$291,120	$42,088	$25,783	$31,722	$95,636	$133,504	$13,379	$1,124	$10,018	$15,325
Other Production	$14,559,733	$4,280,725	$618,880	$379,116	$466,449	$1,406,255	$1,963,080	$196,724	$16,530	$147,310	$225,341
Transmission - Kentucky System Property	$35,222,000	$10,355,665	$1,497,155	$917,134	$1,128,405	$3,401,924	$4,748,961	$475,904	$39,989	$356,363	$545,131
Transmission - Virginia Property	$599,904	$176,379	$25,500	$15,621	$19,219	$57,942	$80,885	$8,106	$681	$6,070	$9,285
Distribution	$15,538,047	$2,941	$1,177,853	$4,036	$801,123	$2,304	$4,644,676	$22,418,718	$4,154,003	$5,210,840	$6,253,142
General Plant	$4,736,837	$1,260,253	$216,353	$111,722	$160,553	$414,043	$712,625	$708,221	$125,363	$194,518	$247,724
Intangible Plant	$1,705,833	$453,843	$77,913	$40,233	$57,818	$149,105	$256,631	$255,045	$45,146	$70,050	$89,210
TOTAL ACCUMULATED RESERVE FOR DEPRECIATION	$184,311,170	$49,444,019	$8,372,177	$4,382,862	$6,220,064	$16,244,173	$27,500,847	$25,575,318	$4,508,814	$7,117,805	$9,102,466
Rate Base Adjustments and Working Capital											
Working Capital Assets											
Cash Working Capital - Operation and Maintenance Expenses	$9,915,650	$2,865,771	$412,330	$238,400	$320,896	$917,667	$1,407,303	$300,273	$34,449	$181,424	$247,479
Materials and Supplies	$7,884,315	$2,097,650	$360,113	$185,958	$267,235	$689,161	$1,186,141	$1,178,811	$208,663	$323,769	$412,328
Prepayments	$154,786	$41,181	$7,070	$3,651	$5,246	$13,530	$23,286	$23,143	$4,096	$6,356	$8,095
Sub-total	$17,954,751	$5,004,603	$779,513	$428,009	$593,377	$1,620,358	$2,616,731	$1,502,227	$247,208	$511,549	$667,902
Other Rate Base Items											
Deferred Debits											
Total Production Plant	$19,840,407	$5,833,303	$843,341	$516,618	$635,626	$1,916,290	$2,675,070	$268,075	$22,526	$200,738	$307,070
Total Transmission Plant	$3,381,323	$994,147	$143,727	$88,045	$108,327	$326,586	$455,902	$45,687	$3,839	$34,211	$52,333
Total Distribution Plant	$2,702,490	$512	$204,861	$702	$139,337	$401	$807,836	$3,899,226	$722,494	$906,307	$1,087,592
Total General Plant	$707,008	$188,102	$32,292	$16,675	$23,984	$61,799	$106,364	$105,707	$18,711	$29,033	$36,975
Sub-total	$26,631,228	$7,016,064	$1,224,222	$622,040	$907,254	$2,305,075	$4,045,172	$4,318,694	$767,570	$1,170,289	$1,483,969
Accumulated Deferred Investment Tax Credits											
Production	$6,725,955	$1,977,507	$285,895	$175,135	$215,479	$649,628	$906,856	$90,878	$7,636	$68,051	$104,098
Transmission	$10,267	$3,019	$436	$267	$329	$992	$1,384	$139	$12	$104	$159
Transmission VA	$464	$137	$20	$12	$15	$45	$63	$6	$1	$5	$7
Distribution VA	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Distribution Plant KY,FERC & TN	$3,317	$1	$251	$1	$171	$0	$992	$4,786	$887	$1,112	$1,335
General	$1,720	$458	$79	$41	$58	$150	$259	$257	$46	$71	$90
Sub-total	$6,741,723	$1,981,120	$286,681	$175,456	$216,052	$650,815	$909,554	$96,066	$8,581	$69,342	$105,689
Customer Advances											
Customer Advances	$120,341	$9	$9,079	$16	$6,203	$8	$35,991	$13,523	$1,547	$13,350	$11,150
Sub-total	$120,341	$9	$9,079	$16	$6,203	$8	$35,991	$13,523	$1,547	$13,350	$11,150
Emission Allowance											
Emission Allowance	$26,724	$7,857	$1,136	$696	$856	$2,581	$3,603	$361	$30	$270	$414
Sub-total	$26,724	$7,857	$1,136	$696	$856	$2,581	$3,603	$361	$30	$270	$414
TOTAL OTHER RATE BASE	$33,252,610	$8,997,175	$1,501,824	$797,480	$1,117,103	$2,955,883	$4,918,734	$4,401,237	$774,604	$1,226,281	$1,578,508
TOTAL RATE BASE	$295,955,020	$80,803,283	$13,269,079	$7,145,932	$9,894,085	$26,522,617	$43,414,754	$34,297,253	$5,972,091	$9,922,639	$12,826,229

Kentucky Utilities
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	Total	Rate RS	GSS	GSP	AES	LPS	LPP	LPT	STODS	STODP	LCIP	LCIT
O & M Expenses												
Steam Production O&M												
500 OPERATION SUPERVISION & ENGINEERING	$3,348,315	$1,204,814	$334,568	$9,482	$23,674	$679,101	$278,137	$4,444	$33,856	$2,654	$466,290	$137,434
501 FUEL	$359,943,470	$126,113,366	$35,316,100	$821,751	$2,560,614	$73,694,626	$30,540,306	$477,454	$3,674,131	$297,893	$51,636,039	$15,402,001
502 STEAM EXPENSES	$9,025,021	$3,264,395	$905,026	$26,541	$63,734	$1,827,000	$746,500	$11,980	$91,082	$7,090	$1,249,317	$367,313
505 ELECTRIC EXPENSES	$4,868,361	$1,767,421	$490,003	$14,370	$34,507	$989,181	$404,173	$6,466	$49,314	$3,839	$676,410	$198,872
506 MISC. STEAM POWER EXPENSES	$6,423,607	$2,323,451	$644,157	$18,891	$45,363	$1,300,377	$531,325	$8,527	$64,828	$5,046	$889,208	$261,437
507 RENTS	$1,911,917	$691,550	$191,726	$5,623	$13,502	$387,043	$158,143	$2,538	$19,295	$1,502	$264,663	$77,814
510 MAINTENANCE SUPERVISION & ENGINEERING	$4,877,355	$1,648,278	$460,349	$11,112	$33,240	$956,121	$395,455	$6,205	$47,668	$3,843	$667,679	$198,766
511 MAINTENANCE OF STRUCTURES	$4,477,790	$1,619,639	$449,031	$13,168	$31,622	$906,471	$370,378	$5,944	$45,191	$3,518	$619,852	$182,244
512 MAINTENANCE OF BOILER PLANT	$24,647,620	$8,635,785	$2,418,318	$56,271	$175,342	$5,046,340	$2,091,289	$32,694	$251,591	$20,399	$3,535,846	$1,054,673
513 MAINTENANCE OF ELECTRIC PLANT	$9,390,527	$3,290,158	$921,358	$21,439	$66,804	$1,922,611	$796,763	$12,456	$95,854	$7,772	$1,347,127	$401,821
514 MAINTENANCE OF MISC STEAM PLANT	$991,695	$347,460	$97,301	$2,264	$7,055	$203,039	$84,143	$1,315	$10,123	$821	$142,265	$42,435
Sub-total	$429,723,678	$150,904,317	$42,227,937	$1,000,911	$3,055,456	$87,911,910	$36,396,613	$570,043	$4,382,934	$354,376	$61,494,698	$18,324,810
Hydraulic Production O&M												
535 OPERATION SUPERVISION & ENGINEERING	$7,220	$2,611	$724	$21	$51	$1,462	$597	$10	$73	$6	$999	$294
536 WATER FOR POWER	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
537 HYDRAULIC EXPENSES	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
538 ELECTRIC EXPENSES	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
539 MISC. HYDRAULIC POWER EXPENSES	$36,018	$13,028	$3,612	$106	$254	$7,291	$2,979	$48	$364	$28	$4,986	$1,466
540 RENTS	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
541 MAINTENANCE SUPERVISION & ENGINEERING	$104,232	$36,905	$10,300	$260	$740	$21,262	$8,771	$138	$1,060	$85	$14,762	$4,389
542 MAINTENANCE OF STRUCTURES	$135,839	$49,133	$13,622	$399	$959	$27,499	$11,236	$180	$1,371	$107	$18,804	$5,529
543 MAINT. OF RESERVES, DAMS, AND WATERWAYS	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
544 MAINTENANCE OF ELECTRIC PLANT	$136,478	$47,818	$13,391	$312	$971	$27,942	$11,580	$181	$1,393	$113	$19,579	$5,840
545 MAINTENANCE OF MISC HYDRAULIC PLANT	$5,457	$1,912	$535	$12	$39	$1,117	$463	$7	$56	$5	$783	$234
Sub-total	$425,244	$151,408	$42,184	$1,111	$3,014	$86,574	$35,626	$564	$4,316	$343	$59,932	$17,751
Other Power Generation Operation Expense												
546 OPERATION SUPERVISION & ENGINEERING	$99,030	$35,820	$9,931	$291	$699	$20,047	$8,191	$131	$999	$78	$13,708	$4,030
547 FUEL	$50,197,106	$17,587,556	$4,925,124	$114,600	$357,099	$10,277,328	$4,259,099	$66,585	$512,388	$41,544	$7,201,074	$2,147,937
548 GENERATION EXPENSE	$1,459,910	$528,057	$146,399	$4,293	$10,310	$295,540	$120,756	$1,938	$14,734	$1,147	$202,093	$59,417
549 MISC OTHER POWER GENERATION	$114,052	$41,253	$11,437	$335	$805	$23,088	$9,434	$151	$1,151	$90	$15,788	$4,642
550 RENTS	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
551 MAINTENANCE SUPERVISION & ENGINEERING	$33,775	$12,216	$3,387	$99	$239	$6,837	$2,794	$45	$341	$27	$4,675	$1,375
552 MAINTENANCE OF STRUCTURES	$143,980	$52,078	$14,438	$423	$1,017	$29,147	$11,909	$191	$1,453	$113	$19,931	$5,860
553 MAINTENANCE OF GENERATING & ELEC PLANT	$2,313,971	$838,975	$232,044	$6,805	$16,341	$468,434	$191,399	$3,072	$23,353	$1,818	$320,319	$94,177
554 MAINTENANCE OF MISC OTHER POWER GEN PLT	$247,222	$89,422	$24,791	$727	$1,746	$50,047	$20,449	$328	$2,495	$194	$34,223	$10,062
Sub-total	$54,609,046	$19,183,377	$5,367,551	$127,575	$388,256	$11,170,468	$4,624,031	$72,441	$556,914	$45,010	$7,811,811	$2,327,500
Other Power Supply Expense												
555 PURCHASED POWER												
'Demand	$15,031,259	$5,436,881	$1,507,330	$44,204	$106,150	$3,042,886	$1,243,303	$19,952	$151,699	$11,808	$2,080,749	$611,764
'Energy	$142,211,384	$49,826,592	$13,953,167	$324,669	$1,011,682	$29,116,280	$12,066,281	$188,639	$1,451,626	$117,696	$20,401,072	$6,085,233
555 PURCHASED POWER OPTIONS	$0											
555 BROKERAGE FEES	$0											
555 MISO TRANSMISSION EXPENSES	$0											
556 SYSTEM CONTROL AND LOAD DISPATCH	$1,341,969	$485,397	$134,572	$3,947	$9,477	$271,664	$111,000	$1,781	$13,543	$1,054	$185,768	$54,617
557 OTHER EXPENSES	$1,040,935	$376,512	$104,385	$3,061	$7,351	$210,724	$86,100	$1,382	$10,505	$818	$144,095	$42,365
Sub-total	$159,625,546	$56,125,382	$15,699,454	$375,881	$1,134,660	$32,641,554	$13,506,685	$211,754	$1,627,373	$131,376	$22,811,682	$6,793,980
Transmission Expenses												
560 OPERATION SUPERVISION AND ENG	$888,516	$321,381	$89,100	$2,613	$6,275	$179,869	$73,493	$1,179	$8,967	$698	$122,996	$36,162
561 LOAD DISPATCHING	$842,754	$304,828	$84,511	$2,478	$5,951	$170,605	$69,708	$1,119	$8,505	$662	$116,661	$34,300
562 STATION EXPENSES	$361,025	$130,585	$36,204	$1,062	$2,550	$73,085	$29,862	$479	$3,644	$284	$49,976	$14,694
563 OVERHEAD LINE EXPENSES	$335,768	$121,448	$33,670	$987	$2,371	$67,971	$27,773	$446	$3,389	$264	$46,479	$13,665
565 TRANSMISSION OF ELECTRICITY BY OTHERS	$4,617,906	$1,670,320	$463,082	$13,580	$32,611	$934,836	$381,968	$6,130	$46,605	$3,628	$639,248	$187,946
566 MISC. TRANSMISSION EXPENSES	$4,624,059	$1,672,545	$463,699	$13,599	$32,655	$936,082	$382,477	$6,138	$46,667	$3,633	$640,100	$188,197
567 RENTS	$88,823	$32,128	$8,907	$261	$627	$17,981	$7,347	$118	$896	$70	$12,296	$3,615
568 MAINTENACE SUPERVISION AND ENG	$0											
569 STRUCTURES	$0											
570 MAINT OF STATION EQUIPMENT	$915,531	$331,152	$91,809	$2,692	$6,465	$185,337	$75,728	$1,215	$9,240	$719	$126,735	$37,262
571 MAINT OF OVERHEAD LINES	$3,300,624	$1,193,852	$330,986	$9,707	$23,309	$668,169	$273,009	$4,381	$33,311	$2,593	$456,899	$134,334
572 UNDERGROUND LINES	$0											
573 MISC PLANT	$175,179	$63,363	$17,567	$515	$1,237	$35,463	$14,490	$233	$1,768	$138	$24,250	$7,130
575 MISO DAY 1&2 EXPENSE	$10,185	$3,684	$1,021	$30	$72	$2,062	$842	$14	$103	$8	$1,410	$415
Sub-total	$16,160,369	$5,845,286	$1,620,557	$47,525	$114,123	$3,271,459	$1,336,696	$21,451	$163,094	$12,695	$2,237,050	$657,718

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	Total	Rate RS	GSS	GSP	AES	LPS	LPP	LPT	STODS	STODP	LCIP	LCIT
Distribution Expense - Operating												
580 OPERATION SUPERVISION AND ENGI	$1,284,074	$763,721	$243,914	$2,965	$6,700	$128,728	$29,910	$9	$3,747	$231	$42,988	$36
581 LOAD DISPATCHING	$610,159	$310,797	$64,022	$3,585	$8,427	$98,180	$38,560	$0	$4,285	$308	$58,285	$0
582 STATION EXPENSES	$1,001,284	$510,024	$105,062	$5,883	$10,547	$161,116	$63,278	$0	$7,032	$505	$95,647	$0
583 OVERHEAD LINE EXPENSES	$3,030,139	$1,909,562	$440,194	$8,938	$18,577	$286,026	$95,354	$4	$12,044	$760	$143,237	$13
584 UNDERGROUND LINE EXPENSES	$72,494	$42,055	$10,426	$279	$572	$8,628	$2,991	$0	$377	$24	$4,509	$0
585 STREET LIGHTING EXPENSE	$10,832	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
586 METER EXPENSES	$6,096,249	$3,794,957	$1,674,291	$4,054	$12,979	$481,471	$19,374	$110	$1,433	$55	$2,207	$445
586 METER EXPENSES - LOAD MANAGEMENT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
587 CUSTOMER INSTALLATIONS EXPENSE	-$73,416	-$42,053	-$12,044	-$152	-$421	-$7,553	-$1,611	$0	-$248	-$13	-$2,406	$0
588 MISCELLANEOUS DISTRIBUTION EXP	$4,379,334	$2,508,468	$718,411	$9,074	$25,098	$450,671	$96,078	$7	$14,792	$763	$143,508	$27
588 MISC DISTR EXP -- MAPPIN	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
589 RENTS	$12,654	$7,248	$2,076	$26	$73	$1,302	$278	$0	$43	$2	$415	$0
590 MAINTENANCE SUPERVISION AND EN	$6,387	$3,978	$919	$20	$40	$621	$209	$0	$26	$2	$314	$0
591 STRUCTURES	$628	$320	$66	$4	$7	$101	$40	$0	$4	$0	$60	$0
592 MAINTENANCE OF STATION EQUIPME	$856,534	$436,293	$89,873	$5,032	$9,023	$137,824	$54,130	$0	$6,016	$432	$81,620	$0
593 MAINTENANCE OF OVERHEAD LINES	$20,706,877	$13,049,259	$3,008,125	$61,079	$126,952	$1,954,598	$651,615	$25	$82,302	$5,196	$978,831	$88
594 MAINTENANCE OF UNDERGROUND LIN	$590,308	$342,450	$84,897	$2,271	$4,654	$70,253	$24,352	$0	$3,070	$194	$36,719	$1
595 MAINTENANCE OF LINE TRANSFORME	$110,444	$72,472	$29,298	$0	$515	$6,481	$0	$0	$337	$0	$0	$0
596 MAINTENANCE OF ST LIGHTS & SIG SYSTEMS	$55,955	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
597 MAINTENANCE OF METERS	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
598 MISCELLANEOUS DISTRIBUTION EXPENSES	$7,695	$4,407	$1,262	$16	$44	$792	$169	$0	$26	$1	$252	$0
Sub-total	$38,758,632	$23,713,959	$6,460,794	$103,073	$221,788	$3,779,138	$1,074,727	$155	$135,286	$8,461	$1,588,388	$811
Customer Accounts Expense												
901 SUPERVISION/CUSTOMER ACCTS	$1,853,549	$1,256,875	$261,678	$2,221	$931	$271,345	$10,647	$61	$3,103	$122	$2,373	$426
902 METER READING EXPENSES	$4,126,623	$2,798,228	$582,583	$4,944	$2,072	$604,106	$23,704	$135	$6,908	$271	$5,283	$948
903 RECORDS AND COLLECTION	$11,300,549	$7,662,805	$1,595,373	$13,539	$5,675	$1,654,312	$64,911	$371	$18,917	$742	$14,466	$2,596
904 UNCOLLECTIBLE ACCOUNTS	$3,133,404	$2,124,734	$442,363	$3,754	$1,574	$458,706	$17,999	$103	$5,245	$206	$4,011	$720
905 MISC CUST ACCOUNTS	$227,523	$154,282	$32,121	$273	$114	$33,308	$1,307	$7	$381	$15	$291	$52
Sub-total	$20,641,648	$13,996,924	$2,914,117	$24,730	$10,366	$3,021,777	$118,567	$678	$34,554	$1,355	$26,424	$4,743
Customer Service & Information Expense												
907 SUPERVISION	$217,872	$173,269	$32,795	$31	$128	$3,741	$147	$1	$21	$1	$16	$3
908 CUSTOMER ASSISTANCE EXPENSES	$4,733,193	$3,764,216	$712,455	$665	$2,788	$81,265	$3,169	$18	$465	$18	$355	$64
908 CUSTOMER ASSISTANCE EXP-INCENTIVES	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
909 INFORMATIONAL AND INSTRUCTIONA	$449,354	$357,363	$67,638	$63	$265	$7,715	$303	$2	$44	$2	$34	$6
909 INFORM AND INSTRUC -LOAD MGMT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
910 MISCELLANEOUS CUSTOMER SERVICE	$765,960	$625,059	$118,305	$110	$463	$13,494	$529	$3	$77	$3	$59	$11
911 DEMONSTRATION AND SELLING EXP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
912 DEMONSTRATION AND SELLING EXP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
913 ADVERTISING EXPENSES	$66,555	$52,930	$10,018	$9	$39	$1,143	$45	$0	$7	$0	$5	$1
915 MDSE-JOBBING-CONTRACT	$0											
916 MISC SALES EXPENSE	$0											
Sub-total	$6,252,934	$4,972,836	$941,211	$879	$3,683	$107,358	$4,212	$24	$614	$24	$469	$84
General Expenses												
920 ADMIN. & GEN. SALARIES-	$14,199,205	$6,785,813	$1,796,263	$34,590	$80,551	$2,329,220	$786,803	$10,631	$97,963	$7,379	$1,280,983	$330,284
921 OFFICE SUPPLIES AND EXPENSES	$6,808,062	$3,253,579	$861,250	$16,585	$38,622	$1,116,786	$377,247	$5,097	$46,970	$3,538	$614,190	$158,361
922 ADMINISTRATIVE EXPENSES TRANSFERRED	-$1,409,208	-$673,462	-$178,271	-$3,433	-$7,994	-$231,165	-$78,087	-$1,055	-$9,722	-$732	-$127,132	-$32,779
923 OUTSIDE SERVICES EMPLOYED	$9,557,040	$4,567,319	$1,209,008	$23,281	$54,217	$1,567,725	$529,572	$7,155	$65,936	$4,966	$862,189	$222,304
924 PROPERTY INSURANCE	$2,804,917	$1,196,672	$336,290	$7,499	$18,660	$481,931	$179,573	$2,579	$22,515	$1,676	$297,122	$79,050
925 INJURIES AND DAMAGES - INSURAN	$1,723,528	$823,676	$218,034	$4,199	$9,778	$282,725	$95,504	$1,290	$11,891	$896	$155,488	$40,091
926 EMPLOYEE BENEFITS	$20,838,595	$9,958,784	$2,638,175	$50,763	$118,216	$3,418,337	$1,154,703	$15,601	$143,770	$10,829	$1,879,956	$484,722
928 REGULATORY COMMISSION FEES	$529,026	$225,700	$63,427	$1,414	$3,519	$90,896	$33,869	$486	$4,246	$316	$56,039	$14,909
929 DUPLICATE CHARGES	-$2,928	-$1,399	-$370	-$7	-$17	-$480	-$162	-$2	-$20	-$2	-$264	-$68
930 MISCELLANEOUS GENERAL EXPENSES	$1,240,888	$593,022	$156,978	$3,023	$7,040	$203,554	$68,760	$929	$8,561	$645	$111,947	$28,864
931 RENTS AND LEASES	$1,396,179	$595,657	$167,392	$3,733	$9,288	$239,887	$89,385	$1,284	$11,207	$834	$147,896	$39,346
932 MAINTENANCE OF GENERAL PLANT	$0											
935 MAINTENANCE OF GENERAL PLANT	$5,618,834	$2,397,183	$673,660	$15,023	$37,380	$965,409	$359,723	$5,167	$45,102	$3,358	$595,198	$158,354
Sub-total	$63,304,138	$29,722,545	$7,939,837	$156,669	$369,260	$10,464,824	$3,596,889	$49,163	$448,418	$33,703	$5,873,612	$1,523,441
TOTAL O & M EXPENSES	$789,601,237	$304,616,034	$83,213,642	$1,838,353	$5,300,606	$162,465,062	$60,694,046	$926,273	$7,353,503	$587,344	$101,902,083	$29,650,637
TOTAL O&M EXPENSE Less PURCHASED POWER	$632,258,694	$249,352,560	$67,763,146	$1,469,480	$4,182,774	$120,295,898	$47,384,482	$717,682	$5,750,178	$457,840	$79,420,243	$22,953,640

Depreciation Expense

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	Total	Rate RS	GSS	GSP	AES	LPS	LPP	LPT	STODS	STODP	LCIP	LCIT
Steam Production	$41,922,608	$15,163,616	$4,203,986	$123,287	$296,055	$8,486,694	$3,467,607	$55,647	$423,081	$32,934	$5,803,268	$1,706,226
Hydraulic Production	$150,640	$54,487	$15,106	$443	$1,064	$30,495	$12,460	$200	$1,520	$118	$20,853	$6,131
Other Production	$14,711,364	$5,321,174	$1,475,251	$43,264	$103,891	$2,978,127	$1,216,843	$19,528	$148,470	$11,557	$2,036,467	$598,744
Transmission - Kentucky System Property	$12,173,047	$4,403,052	$1,220,709	$35,799	$85,965	$2,464,277	$1,006,887	$16,158	$122,853	$9,563	$1,685,092	$495,436
Transmission - Virginia Property	$216,042	$78,144	$21,665	$635	$1,526	$43,735	$17,870	$287	$2,180	$170	$29,906	$8,793
Distribution	$30,450,891	$17,442,169	$4,995,341	$63,096	$174,516	$3,132,964	$668,063	$49	$102,852	$5,306	$997,853	$189
General Plant	$4,599,109	$1,962,135	$551,402	$12,296	$30,596	$790,204	$294,439	$4,229	$36,917	$2,748	$487,179	$129,616
Intangible Plant	$5,512,422	$2,351,784	$660,902	$14,738	$36,872	$947,126	$352,910	$5,069	$44,248	$3,294	$583,926	$155,355
TOTAL DEPRECIATION EXPENSES	$109,736,123	$46,776,669	$13,144,361	$293,659	$730,284	$18,873,622	$7,037,078	$101,167	$882,131	$66,691	$11,644,644	$3,100,490
Other Expenses												
Regulatory Credits and Accretion Expense												
Production	-$255,036	-$92,248	-$25,575	-$750	-$1,801	-$51,629	-$21,095	-$339	-$2,574	-$200	-$35,304	-$10,380
Transmission	-$156	-$56	-$16	$0	-$1	-$32	-$13	$0	-$2	$0	-$22	-$6
Distribution	-$182	-$104	-$30	$0	-$1	-$19	-$4	$0	-$1	$0	-$6	$0
Property Taxes & Other	$10,473,065	$4,468,162	$1,255,649	$28,001	$69,673	$1,799,447	$670,495	$9,631	$84,068	$6,258	$1,109,402	$295,160
Other Taxes	$6,763,965	$2,885,735	$810,953	$18,084	$44,998	$1,162,162	$433,035	$6,220	$54,294	$4,042	$716,500	$190,627
Gain on Disposition of Allowances	-$504,602	-$208,908	-$58,544	-$1,367	-$3,393	-$89,744	-$34,153	-$504	-$4,253	-$320	-$56,676	-$15,474
Interest	$56,236,895	$23,282,406	$6,524,588	$152,402	$378,140	$10,001,833	$3,806,259	$56,181	$473,946	$35,705	$6,316,416	$1,724,543
Other Expenses	$0											
Total Other Expenses	$72,713,948	$30,334,985	$8,507,026	$196,369	$487,615	$12,822,016	$4,854,523	$71,189	$605,478	$45,484	$8,050,311	$2,184,471
TOTAL EXPENSES	$971,951,308	$381,727,576	$104,665,029	$2,328,281	$6,518,505	$184,150,702	$72,585,646	$1,088,629	$8,841,111	$698,519	$121,596,918	$34,935,596

Calculation of Taxable Income and Allocation of Income Taxes:

	Total	Rate RS	GSS	GSP	AES	LPS	LPP	LPT	STODS	STODP	LCIP	LCIT
Total Operating Revenue	$1,154,156,041	$434,201,182	$141,196,389	$3,110,064	$7,940,212	$226,074,364	$86,951,352	$1,370,360	$9,536,117	$765,874	$135,173,608	$35,809,536
Operating Expenses	$915,714,413	$358,445,172	$98,340,441	$2,175,879	$6,140,365	$174,146,869	$68,779,389	$1,042,448	$8,367,165	$662,814	$115,280,501	$33,211,055
Interest Expense	$56,236,895	$23,282,406	$6,524,588	$152,402	$378,140	$10,001,833	$3,806,259	$56,181	$473,946	$35,705	$6,316,416	$1,724,543
Taxable Income	**$182,204,733**	**$52,473,604**	**$36,331,360**	**$781,783**	**$1,421,707**	**$41,923,662**	**$14,365,704**	**$271,731**	**$695,006**	**$67,355**	**$13,576,691**	**$873,938**
Income Taxes												
State & Federal Income Taxes	$56,084,862	$16,146,262	$11,179,252	$240,557	$437,463	$12,900,018	$4,420,364	$83,612	$213,855	$20,725	$4,177,582	$268,913

Kentucky Utilities
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	MPP	MPT	LMPP	LMPT	LITOD	SL	SLDEC	POL	OL
O & M Expenses									
Steam Production O&M									
500 OPERATION SUPERVISION & ENGINEERING	$19,623	$12,017	$14,914	$44,914	$63,099	$6,478	$544	$4,851	$7,421
501 FUEL	$2,066,688	$1,263,648	$1,638,084	$4,907,408	$7,111,173	$813,276	$68,338	$608,992	$931,581
502 STEAM EXPENSES	$53,104	$32,531	$40,024	$120,666	$168,445	$16,880	$1,418	$12,640	$19,336
505 ELECTRIC EXPENSES	$28,752	$17,613	$21,670	$65,331	$91,200	$9,139	$768	$6,844	$10,469
506 MISC. STEAM POWER EXPENSES	$37,797	$23,154	$28,487	$85,884	$119,891	$12,015	$1,010	$8,997	$13,762
507 RENTS	$11,250	$6,891	$8,479	$25,563	$35,684	$3,576	$300	$2,678	$4,096
510 MAINTENANCE SUPERVISION & ENGINEERING	$26,950	$16,483	$21,210	$63,596	$91,687	$10,312	$866	$7,722	$11,812
511 MAINTENANCE OF STRUCTURES	$26,348	$16,140	$19,858	$59,869	$83,574	$8,375	$704	$6,271	$9,593
512 MAINTENANCE OF BOILER PLANT	$141,519	$86,530	$112,170	$336,041	$486,947	$55,690	$4,680	$41,702	$63,791
513 MAINTENANCE OF ELECTRIC PLANT	$53,918	$32,967	$42,736	$128,029	$185,523	$21,217	$1,783	$15,888	$24,304
514 MAINTENANCE OF MISC STEAM PLANT	$5,694	$3,482	$4,513	$13,521	$19,592	$2,241	$188	$1,678	$2,567
Sub-total	$2,471,641	$1,511,456	$1,952,146	$5,850,821	$8,456,817	$959,200	$80,600	$718,261	$1,098,731
Hydraulic Production O&M									
535 OPERATION SUPERVISION & ENGINEERING	$42	$26	$32	$97	$135	$14	$1	$10	$15
536 WATER FOR POWER	$0	$0	$0	$0	$0	$0	$0	$0	$0
537 HYDRAULIC EXPENSES	$0	$0	$0	$0	$0	$0	$0	$0	$0
538 ELECTRIC EXPENSES	$0	$0	$0	$0	$0	$0	$0	$0	$0
539 MISC. HYDRAULIC POWER EXPENSES	$212	$130	$160	$482	$672	$67	$6	$50	$77
540 RENTS	$0	$0	$0	$0	$0	$0	$0	$0	$0
541 MAINTENANCE SUPERVISION & ENGINEERING	$603	$369	$470	$1,412	$2,022	$222	$19	$166	$255
542 MAINTENANCE OF STRUCTURES	$799	$490	$602	$1,816	$2,535	$254	$21	$190	$291
543 MAINT. OF RESERVES, DAMS, AND WATERWAYS	$0	$0	$0	$0	$0	$0	$0	$0	$0
544 MAINTENANCE OF ELECTRIC PLANT	$784	$479	$621	$1,861	$2,696	$308	$26	$231	$353
545 MAINTENANCE OF MISC HYDRAULIC PLANT	$31	$19	$25	$74	$108	$12	$1	$9	$14
Sub-total	$2,472	$1,513	$1,911	$5,742	$8,169	$878	$74	$657	$1,005
Other Power Generation Operation Expense									
546 OPERATION SUPERVISION & ENGINEERING	$583	$357	$439	$1,324	$1,848	$185	$16	$139	$212
547 FUEL	$288,217	$176,226	$228,444	$684,379	$991,712	$113,418	$9,530	$84,929	$129,917
548 GENERATION EXPENSE	$8,590	$5,262	$6,474	$19,519	$27,248	$2,731	$229	$2,045	$3,128
549 MISC OTHER POWER GENERATION	$671	$411	$506	$1,525	$2,129	$213	$18	$160	$244
550 RENTS	$0	$0	$0	$0	$0	$0	$0	$0	$0
551 MAINTENANCE SUPERVISION & ENGINEERING	$189	$122	$150	$452	$630	$63	$5	$47	$72
552 MAINTENANCE OF STRUCTURES	$847	$519	$639	$1,925	$2,687	$269	$23	$202	$308
553 MAINTENANCE OF GENERATING & ELEC PLANT	$13,616	$8,341	$10,262	$30,938	$43,188	$4,328	$364	$3,241	$4,958
554 MAINTENANCE OF MISC OTHER POWER GEN PLT	$1,455	$891	$1,096	$3,305	$4,614	$462	$39	$346	$530
Sub-total	$314,177	$192,129	$248,011	$743,367	$1,074,057	$121,670	$10,224	$91,108	$139,369
Other Power Supply Expense									
555 PURCHASED POWER									
'Demand	$88,445	$54,180	$66,661	$200,970	$280,546	$28,114	$2,362	$21,052	$32,204
'Energy	$816,535	$499,260	$647,197	$1,938,886	$2,809,579	$321,320	$27,000	$240,609	$368,062
555 PURCHASED POWER OPTIONS									
555 BROKERAGE FEES									
555 MISO TRANSMISSION EXPENSES									
556 SYSTEM CONTROL AND LOAD DISPATCH	$7,896	$4,837	$5,951	$17,942	$25,047	$2,510	$211	$1,880	$2,875
557 OTHER EXPENSES	$6,125	$3,752	$4,616	$13,917	$19,428	$1,947	$164	$1,458	$2,230
Sub-total	$919,001	$562,029	$724,425	$2,171,715	$3,134,600	$353,891	$29,737	$264,998	$405,371
Transmission Expenses									
560 OPERATION SUPERVISION AND ENG	$5,228	$3,203	$3,940	$11,880	$16,583	$1,662	$140	$1,244	$1,904
561 LOAD DISPATCHING	$4,959	$3,038	$3,737	$11,268	$15,729	$1,576	$132	$1,180	$1,806
562 STATION EXPENSES	$2,124	$1,301	$1,601	$4,827	$6,738	$675	$57	$506	$773
563 OVERHEAD LINE EXPENSES	$1,976	$1,210	$1,489	$4,489	$6,267	$628	$53	$470	$719
565 TRANSMISSION OF ELECTRICITY BY OTHERS	$27,172	$16,645	$20,480	$61,742	$86,189	$8,637	$726	$6,468	$9,894
566 MISC. TRANSMISSION EXPENSES	$27,208	$16,667	$20,507	$61,824	$86,304	$8,649	$727	$6,476	$9,907
567 RENTS	$523	$320	$394	$1,188	$1,658	$166	$14	$124	$190
568 MAINTENACE SUPERVISION AND ENG									
569 STRUCTURES									
570 MAINT OF STATION EQUIPMENT	$5,387	$3,300	$4,060	$12,241	$17,088	$1,712	$144	$1,282	$1,961
571 MAINT OF OVERHEAD LINES	$19,421	$11,897	$14,638	$44,130	$61,603	$6,173	$519	$4,623	$7,071
572 UNDERGROUND LINES									
573 MISC PLANT	$1,031	$631	$777	$2,342	$3,270	$328	$28	$245	$375
575 MISO DAY 1&2 EXPENSE	$60	$37	$45	$136	$190	$19	$2	$14	$22
Sub-total	$95,089	$58,250	$71,668	$216,066	$301,620	$30,226	$2,540	$22,634	$34,623

Kentucky Utilities
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	MPP	MPT	LMPP	LMPT	LITOD	SL	SLDEC	POL	OL
Distribution Expense - Operating									
580 OPERATION SUPERVISION AND ENGI	$3,353	$46	$2,220	$28	$12,811	$22,920	$3,445	$9,840	$6,462
581 LOAD DISPATCHING	$4,379	$0	$3,004	$0	$17,439	$298	$25	$223	$341
582 STATION EXPENSES	$7,186	$0	$4,929	$0	$28,617	$489	$41	$366	$560
583 OVERHEAD LINE EXPENSES	$10,813	$22	$7,384	$11	$42,836	$18,582	$2,130	$18,375	$15,278
584 UNDERGROUND LINE EXPENSES	$339	$0	$232	$0	$1,349	$243	$27	$237	$205
585 STREET LIGHTING EXPENSE	$0	$0	$0	$0	$0	$6,815	$1,317	$1,091	$1,609
586 METER EXPENSES	$1,664	$549	$165	$335	$43	$48,782	$0	$53,336	$0
586 METER EXPENSES - LOAD MANAGEMENT	$0	$0	$0	$0	$0	$0	$0	$0	$0
587 CUSTOMER INSTALLATIONS EXPENSE	-$182	-$1	-$124	$0	-$719	-$3,471	-$643	-$807	-$988
588 MISCELLANEOUS DISTRIBUTION EXP	$10,879	$37	$7,399	$21	$42,898	$207,057	$38,366	$48,127	$57,753
588 MISC DISTR EXP -- MAPPIN	$0	$0	$0	$0	$0	$0	$0	$0	$0
589 RENTS	$31	$0	$21	$0	$124	$598	$111	$139	$167
590 MAINTENANCE SUPERVISION AND EN	$24	$0	$16	$0	$94	$47	$8	$38	$33
591 STRUCTURES	$5	$0	$3	$0	$18	$0	$0	$0	$0
592 MAINTENANCE OF STATION EQUIPME	$6,147	$0	$4,217	$0	$24,480	$418	$35	$313	$479
593 MAINTENANCE OF OVERHEAD LINES	$73,895	$151	$50,457	$76	$292,723	$126,981	$14,556	$125,566	$104,402
594 MAINTENANCE OF UNDERGROUND LIN	$2,764	$2	$1,893	$1	$10,984	$1,981	$223	$1,928	$1,670
595 MAINTENANCE OF LINE TRANSFORME	$0	$0	$0	$0	$0	$458	$52	$452	$377
596 MAINTENANCE OF ST LIGHTS & SIG SYSTEMS	$0	$0	$0	$0	$0	$35,203	$6,805	$5,634	$8,313
597 MAINTENANCE OF METERS	$0	$0	$0	$0	$0	$0	$0	$0	$0
598 MISCELLANEOUS DISTRIBUTION EXPENSES	$19	$0	$13	$0	$75	$364	$67	$85	$101
Sub-total	$121,317	$807	$81,828	$472	$473,771	$467,766	$66,566	$264,943	$196,784
Customer Accounts Expense									
901 SUPERVISION/CUSTOMER ACCTS	$913	$304	$183	$426	$61	$17,844	$2,291	$7,374	$14,373
902 METER READING EXPENSES	$2,032	$677	$406	$948	$135	$39,727	$5,100	$16,417	$32,000
903 RECORDS AND COLLECTION	$5,564	$1,855	$1,113	$2,596	$371	$108,791	$13,985	$44,956	$87,630
904 UNCOLLECTIBLE ACCOUNTS	$1,543	$514	$309	$720	$103	$30,166	$3,872	$12,465	$24,298
905 MISC CUST ACCOUNTS	$112	$37	$22	$52	$7	$2,190	$281	$905	$1,764
Sub-total	$10,163	$3,388	$2,033	$4,743	$678	$198,719	$25,509	$82,116	$160,066
Customer Service & Information Expense									
907 SUPERVISION	$13	$4	$1	$3	$0	$3,280	$421	$1,355	$2,642
908 CUSTOMER ASSISTANCE EXPENSES	$273	$91	$27	$64	$9	$71,253	$9,147	$29,436	$57,396
908 CUSTOMER ASSISTANCE EXP-INCENTIVES	$0	$0	$0	$0	$0	$0	$0	$0	$0
909 INFORMATIONAL AND INSTRUCTIONA	$26	$9	$3	$6	$1	$6,765	$868	$2,795	$5,449
909 INFORM AND INSTRUC -LOAD MGMT	$0	$0	$0	$0	$0	$0	$0	$0	$0
910 MISCELLANEOUS CUSTOMER SERVICE	$45	$15	$5	$11	$2	$11,832	$1,519	$4,888	$9,531
911 DEMONSTRATION AND SELLING EXP	$0	$0	$0	$0	$0	$0	$0	$0	$0
912 DEMONSTRATION AND SELLING EXP	$0	$0	$0	$0	$0	$0	$0	$0	$0
913 ADVERTISING EXPENSES	$4	$1	$0	$1	$0	$1,002	$129	$414	$807
915 MDSE-JOBBING-CONTRACT									
916 MISC SALES EXPENSE									
Sub-total	$361	$120	$36	$84	$12	$94,131	$12,084	$38,887	$75,825
General Expenses									
920 ADMIN. & GEN. SALARIES-	$59,869	$28,793	$44,213	$107,565	$200,403	$97,632	$13,122	$49,918	$57,211
921 OFFICE SUPPLIES AND EXPENSES	$28,705	$13,805	$21,199	$51,574	$96,087	$46,811	$6,292	$23,934	$27,431
922 ADMINISTRATIVE EXPENSES TRANSFERRED	-$5,942	-$2,858	-$4,388	-$10,675	-$19,889	-$9,690	-$1,302	-$4,954	-$5,678
923 OUTSIDE SERVICES EMPLOYED	$40,296	$19,379	$29,758	$72,399	$134,885	$65,713	$8,832	$33,598	$38,507
924 PROPERTY INSURANCE	$13,571	$7,008	$10,071	$25,971	$44,700	$44,424	$7,864	$12,201	$15,539
925 INJURIES AND DAMAGES - INSURAN	$7,287	$3,495	$5,367	$13,056	$24,325	$11,851	$1,593	$6,059	$6,944
926 EMPLOYEE BENEFITS	$87,863	$42,256	$64,886	$157,861	$294,109	$143,284	$19,258	$73,259	$83,962
928 REGULATORY COMMISSION FEES	$2,560	$1,322	$1,899	$4,898	$8,431	$8,379	$1,483	$2,301	$2,931
929 DUPLICATE CHARGES	-$12	-$6	-$9	-$22	-$41	-$20	-$3	-$10	-$12
930 MISCELLANEOUS GENERAL EXPENSES	$5,232	$2,516	$3,864	$9,400	$17,513	$8,532	$1,147	$4,362	$5,000
931 RENTS AND LEASES	$6,755	$3,488	$5,013	$12,927	$22,250	$22,112	$3,914	$6,073	$7,735
932 MAINTENANCE OF GENERAL PLANT									
935 MAINTENANCE OF GENERAL PLANT	$27,185	$14,038	$20,174	$52,026	$89,543	$88,990	$15,752	$24,442	$31,127
Sub-total	$273,350	$133,237	$202,047	$496,981	$912,315	$528,016	$77,951	$231,163	$270,696
TOTAL O & M EXPENSES	$4,207,671	$2,462,928	$3,284,104	$9,489,990	$14,362,038	$2,764,499	$305,283	$1,714,789	$2,382,470
TOTAL O&M EXPENSE Less PURCHASED POWER	$3,302,690	$1,909,488	$2,570,247	$7,350,135	$11,271,913	$2,405,066	$275,920	$1,453,128	$1,982,206

Depreciation Expense

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	MPP	MPT	LMPP	LMPT	LITOD	SL	SLDEC	POL	OL
Steam Production	$246,875	$151,109	$185,919	$560,510	$782,451	$78,411	$6,589	$58,715	$89,817
Hydraulic Production	$886	$543	$668	$2,014	$2,812	$282	$24	$211	$323
Other Production	$86,563	$53,027	$65,242	$196,693	$274,576	$27,516	$2,312	$20,604	$31,518
Transmission - Kentucky System Property	$71,627	$43,878	$53,985	$162,755	$227,200	$22,768	$1,913	$17,049	$26,080
Transmission - Virginia Property	$1,271	$779	$958	$2,889	$4,032	$404	$34	$303	$463
Distribution	$75,642	$259	$51,448	$148	$298,281	$1,439,730	$266,770	$334,640	$401,677
General Plant	$22,252	$11,490	$16,513	$42,584	$73,293	$72,840	$12,893	$20,006	$25,478
Intangible Plant	$26,671	$13,772	$19,792	$51,040	$87,848	$87,305	$15,454	$23,979	$30,538
TOTAL DEPRECIATION EXPENSES	$531,586	$274,858	$394,626	$1,018,632	$1,750,492	$1,729,266	$305,989	$475,507	$605,794
Other Expenses									
Regulatory Credits and Accretion Expense									
Production	-$1,501	-$919	-$1,131	-$3,410	-$4,760	-$477	-$40	-$357	-$546
Transmission	-$1	-$1	-$1	-$2	-$3	$0	$0	$0	$0
Distribution	$0	$0	$0	$0	-$2	-$9	-$2	-$2	-$2
Property Taxes & Other	$50,672	$26,166	$37,603	$96,972	$166,902	$165,870	$29,361	$45,558	$58,019
Other Taxes	$32,726	$16,899	$24,285	$62,629	$107,793	$107,126	$18,963	$29,423	$37,471
Gain on Disposition of Allowances	-$2,541	-$1,368	-$1,895	-$5,079	-$8,314	-$6,568	-$1,144	-$1,900	-$2,456
Interest	$283,195	$152,512	$211,164	$566,059	$926,679	$731,989	$127,459	$211,774	$273,744
Other Expenses									
Total Other Expenses	$362,549	$193,289	$270,026	$717,168	$1,188,195	$997,932	$174,597	$284,495	$366,228
TOTAL EXPENSES	$5,101,706	$2,931,074	$3,948,655	$11,225,781	$17,300,725	$5,481,686	$785,869	$2,474,791	$3,354,492

Calculation of Taxable Income and Allocation of Income Taxes:

	MPP	MPT	LMPP	LMPT	LITOD	SL	SLDEC	POL	OL
Total Operating Revenue	$6,896,875	$3,993,096	$4,916,425	$13,992,126	$23,247,719	$7,371,816	$1,376,780	$4,131,161	$6,100,984
Operating Expenses	$4,818,511	$2,778,562	$3,737,490	$10,659,732	$16,374,146	$4,749,697	$658,410	$2,263,017	$3,080,749
Interest Expense	$283,195	$152,512	$211,164	$566,059	$926,579	$731,989	$127,459	$211,774	$273,744
Taxable Income	$1,795,169	$1,062,022	$967,771	$2,766,335	$5,946,994	$1,890,130	$590,911	$1,656,370	$2,746,492
Income Taxes									
State & Federal Income Taxes	$552,378	$326,787	$297,786	$851,208	$1,828,905	$581,598	$181,825	$509,669	$845,103

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	Total	Rate RS	GSS	GSP	AES	LPS	LPP	LPT	STODS	STODP	LCIP
Labor O & M Expenses											
Labor Expenses											
Steam Power Generation Operation Expenses											
500 OPERATION SUPERVISION & ENGINEERING	$2,086,714	$750,856	$208,507	$5,909	$14,754	$423,224	$173,339	$2,770	$21,099	$1,654	$290,598
501 FUEL	$1,737,173	$608,653	$170,444	$3,966	$12,358	$355,668	$147,395	$2,304	$17,732	$1,438	$249,208
502 STEAM EXPENSES	$5,091,499	$1,841,620	$510,574	$14,973	$35,956	$1,030,709	$421,141	$6,758	$51,384	$4,000	$704,807
505 ELECTRIC EXPENSES	$3,433,990	$1,242,091	$344,359	$10,099	$24,251	$695,167	$284,041	$4,558	$34,657	$2,698	$475,361
506 MISC. STEAM POWER EXPENSES	$222,596	$80,514	$22,322	$655	$1,572	$45,062	$18,412	$295	$2,246	$175	$30,813
507 RENTS	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Steam Power Operation Expenses	$12,571,972	$4,523,735	$1,256,206	$35,602	$88,891	$2,549,830	$1,044,327	$16,686	$127,119	$9,964	$1,750,787
Steam Power Generation Maintenance Expenses											
510 MAINTENANCE SUPERVISION & ENGINEERING	$3,205,656	$1,128,288	$315,503	$7,616	$22,781	$655,284	$271,028	$4,253	$32,670	$2,634	$457,599
511 MAINTENANCE OF STRUCTURES	$787,400	$284,807	$78,960	$2,316	$5,561	$159,399	$65,129	$1,045	$7,947	$619	$108,998
512 MAINTENANCE OF BOILER PLANT	$3,487,689	$1,221,981	$342,197	$7,962	$24,811	$714,068	$295,922	$4,626	$35,601	$2,886	$500,330
513 MAINTENANCE OF ELECTRIC PLANT	$1,206,726	$422,800	$118,399	$2,755	$8,585	$247,064	$102,388	$1,601	$12,318	$999	$173,112
514 MAINTENANCE OF MISC STEAM PLANT	$103,934	$36,415	$10,198	$237	$739	$21,279	$8,819	$138	$1,061	$86	$14,910
Total Steam Power Generation Maintenance Expense	$8,791,406	$3,094,291	$865,257	$20,886	$62,477	$1,797,094	$743,285	$11,663	$89,596	$7,224	$1,254,949
Total Steam Power Generation Expense	$21,363,377	$7,618,026	$2,121,462	$56,488	$151,368	$4,346,924	$1,787,612	$28,349	$216,715	$17,188	$3,005,736
Hydraulic Power Generation Operation Expenses											
535 OPERATION SUPERVISION & ENGINEERING	$5,529	$2,000	$554	$16	$39	$1,119	$457	$7	$56	$4	$765
536 WATER FOR POWER	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
537 HYDRAULIC EXPENSES	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
538 ELECTRIC EXPENSES	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
539 MISC. HYDRAULIC POWER EXPENSES	$2,262	$818	$227	$7	$16	$458	$187	$3	$23	$2	$313
540 RENTS	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Hydraulic Power Operation Expenses	$7,791	$2,818	$781	$23	$55	$1,577	$644	$10	$79	$6	$1,078
Hydraulic Power Generation Maintenance Expenses											
541 MAINTENANCE SUPERVISION & ENGINEERING	$61,207	$21,672	$6,049	$153	$434	$12,486	$5,151	$81	$622	$50	$8,680
542 MAINTENANCE OF STRUCTURES	$29,661	$10,729	$2,974	$87	$209	$6,005	$2,453	$39	$299	$23	$4,106
543 MAINT. OF RESERVES, DAMS, AND WATERWAYS	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
544 MAINTENANCE OF ELECTRIC PLANT	$58,637	$20,545	$5,753	$134	$417	$12,005	$4,975	$78	$599	$49	$8,412
545 MAINTENANCE OF MISC HYDRAULIC PLANT	$2,568	$900	$252	$6	$18	$526	$218	$3	$26	$2	$368
Total Hydraulic Power Generation Maint. Expense	$152,074	$53,845	$15,028	$380	$1,079	$31,021	$12,797	$202	$1,547	$124	$21,566
Total Hydraulic Power Generation Expense	$159,865	$56,663	$15,810	$403	$1,134	$32,598	$13,442	$212	$1,625	$130	$22,645
Other Power Generation Operation Expense											
546 OPERATION SUPERVISION & ENGINEERING	$68,700	$24,849	$6,889	$202	$485	$13,907	$5,683	$91	$693	$54	$9,510
547 FUEL	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
548 GENERATION EXPENSE	$315,655	$114,174	$31,654	$928	$2,229	$63,900	$26,109	$419	$3,186	$248	$43,696
549 MISC OTHER POWER GENERATION	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
550 RENTS	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Other Power Generation Expenses	$384,355	$139,023	$38,543	$1,130	$2,714	$77,808	$31,792	$510	$3,879	$302	$53,206
Other Power Generation Maintenance Expense											
551 MAINTENANCE SUPERVISION & ENGINEERING	$23,508	$8,503	$2,357	$69	$166	$4,759	$1,944	$31	$237	$18	$3,254

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	Total	Rate RS	GSS	GSP	AES	LPS	LPP	LPT	STODS	STODP	LCIP
552 MAINTENANCE OF STRUCTURES	$68,736	$24,862	$6,893	$202	$485	$13,915	$5,685	$91	$694	$54	$9,515
553 MAINTENANCE OF GENERATING & ELEC PLANT	$299,702	$108,404	$30,054	$881	$2,116	$60,671	$24,790	$398	$3,025	$235	$41,487
554 MAINTENANCE OF MISC OTHER POWER GEN PLT	$64,527	$23,340	$6,471	$190	$456	$13,063	$5,337	$86	$651	$51	$8,932
Total Other Power Generation Maintenance Expense	$456,473	$165,108	$45,775	$1,342	$3,224	$92,407	$37,757	$606	$4,607	$359	$63,189
Total Other Power Generation Expense	$840,828	$304,132	$84,318	$2,473	$5,938	$170,215	$69,549	$1,116	$8,486	$661	$116,394
Total Production Expense	$22,364,070	$7,978,821	$2,221,590	$59,363	$158,440	$4,549,737	$1,870,603	$29,677	$226,826	$17,978	$3,144,775
Purchased Power											
555 PURCHASED POWER	$0										
556 SYSTEM CONTROL AND LOAD DISPATCH	$940,689	$340,252	$94,332	$2,766	$6,643	$190,430	$77,809	$1,249	$9,494	$739	$130,218
557 OTHER EXPENSES	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Purchased Power Labor	$940,689	$340,252	$94,332	$2,766	$6,643	$190,430	$77,809	$1,249	$9,494	$739	$130,218
Transmission Labor Expenses											
560 OPERATION SUPERVISION AND ENG	$576,280	$208,443	$57,789	$1,695	$4,070	$116,660	$47,667	$765	$5,816	$453	$79,773
561 LOAD DISPATCHING	$636,176	$230,108	$63,796	$1,871	$4,493	$128,786	$52,621	$844	$6,420	$500	$88,065
562 STATION EXPENSES	$145,235	$52,532	$14,564	$427	$1,026	$29,401	$12,013	$193	$1,466	$114	$20,105
563 OVERHEAD LINE EXPENSES	$26,006	$9,406	$2,608	$76	$184	$5,265	$2,151	$35	$262	$20	$3,600
566 MISC. TRANSMISSION EXPENSES	$163,103	$58,995	$16,356	$480	$1,152	$33,018	$13,491	$216	$1,646	$128	$22,578
568 MAINTENACE SUPERVISION AND ENG	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
570 MAINT OF STATION EQUIPMENT	$331,101	$119,761	$33,203	$974	$2,338	$67,027	$27,387	$439	$3,342	$260	$45,834
571 MAINT OF OVERHEAD LINES	$74,028	$26,776	$7,423	$218	$523	$14,986	$6,123	$98	$747	$58	$10,247
572 UNDERGROUND LINES	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
573 MISC PLANT	$44,250	$16,005	$4,437	$130	$312	$8,958	$3,660	$59	$447	$35	$6,125
Total Transmission Labor Expenses	$1,996,178	$722,028	$200,176	$5,870	$14,097	$404,101	$165,113	$2,650	$20,146	$1,568	$276,327
Distribution Operation Labor Expense											
580 OPERATION SUPERVISION AND ENGI	$797,280	$474,193	$151,446	$1,841	$4,160	$79,927	$18,571	$6	$2,327	$143	$26,691
581 LOAD DISPATCHING	$476,728	$242,831	$50,022	$2,801	$5,022	$76,710	$30,128	$0	$3,348	$240	$45,539
582 STATION EXPENSES	$467,882	$238,325	$49,093	$2,749	$4,929	$75,286	$29,569	$0	$3,286	$236	$44,694
583 OVERHEAD LINE EXPENSES	$1,667,045	$1,063,158	$245,080	$4,976	$10,343	$159,246	$53,089	$2	$6,705	$423	$79,748
584 UNDERGROUND LINE EXPENSES	$40,998	$23,784	$5,896	$158	$323	$4,879	$1,691	$0	$213	$13	$2,550
585 STREET LIGHTING EXPENSE	$6,061	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
586 METER EXPENSES	$2,458,791	$1,530,614	$675,289	$1,635	$5,235	$194,191	$7,814	$44	$578	$22	$690
586 METER EXPENSES - LOAD MANAGEMENT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
587 CUSTOMER INSTALLATIONS EXPENSE	$2,638	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
588 MISCELLANEOUS DISTRIBUTION EXP	$1,891,059	$1,083,192	$310,220	$3,918	$10,838	$194,563	$41,488	$3	$6,387	$330	$61,969
589 RENTS	$0										
Total Distribution Operation Labor Expense	$7,828,482	$4,656,098	$1,487,047	$18,078	$40,850	$784,803	$182,350	$55	$22,845	$1,408	$262,082
Distribution Maintenance Labor Expense											
590 MAINTENANCE SUPERVISION AND EN	$4,720	$2,939	$679	$14	$30	$459	$154	$0	$19	$1	$232
591 MAINTENANCE OF STRUCTURES	$348	$177	$37	$2	$4	$56	$22	$0	$2	$0	$33
592 MAINTENANCE OF STATION EQUIPME	$310,795	$158,310	$32,611	$1,826	$3,274	$50,010	$19,641	$0	$2,183	$157	$29,689
593 MAINTENANCE OF OVERHEAD LINES	$4,678,164	$2,948,131	$679,605	$13,789	$28,681	$441,589	$147,215	$6	$18,594	$1,174	$221,141
594 MAINTENANCE OF UNDERGROUND LIN	$105,012	$60,920	$15,103	$404	$828	$12,498	$4,332	$0	$546	$35	$6,532
595 MAINTENANCE OF LINE TRANSFORME	$42,160	$27,665	$11,184	$0	$197	$2,474	$0	$0	$129	$0	$0
596 MAINTENANCE OF ST LIGHTS & SIG SYSTEMS	$38,321	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
597 MAINTENANCE OF METERS	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
598 MAINTENANCE OF MISC DISTR PLANT	$56	$32	$9	$0	$0	$6	$1	$0	$0	$0	$2

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	Total	Rate RS	GSS	GSP	AES	LPS	LPP	LPT	STODS	STODP	LCIP
Total Distribution Maintenance Labor Expense	$5,177,577	$3,198,174	$739,228	$16,046	$33,014	$507,091	$171,366	$6	$21,474	$1,367	$257,628
Total Distribution Operation and Maintenance Labor Expenses	$13,006,059	$7,854,272	$2,226,275	$34,124	$73,863	$1,291,894	$353,716	$61	$44,318	$2,775	$519,710
Transmission and Distribution Labor Expenses	$15,002,237	$8,576,300	$2,426,451	$39,994	$87,960	$1,695,995	$518,828	$2,710	$64,464	$4,343	$796,037
Production, Transmission and Distribution Labor Expenses	$38,306,996	$16,895,373	$4,742,373	$102,124	$253,043	$8,436,163	$2,467,240	$33,636	$300,763	$23,060	$4,071,030
Customer Accounts Expense											
901 SUPERVISION/CUSTOMER ACCTS	$1,329,439	$901,481	$187,686	$1,593	$668	$194,620	$7,636	$44	$2,225	$87	$1,702
902 METER READING EXPENSES	$484,456	$328,505	$68,394	$580	$243	$70,921	$2,783	$16	$811	$32	$620
903 RECORDS AND COLLECTION	$4,753,471	$3,223,288	$671,079	$5,695	$2,387	$695,871	$27,304	$156	$7,957	$312	$6,085
904 UNCOLLECTIBLE ACCOUNTS	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
905 MISC CUST ACCOUNTS	$111,733	$75,765	$15,774	$134	$56	$16,357	$642	$4	$187	$7	$143
Total Customer Accounts Labor Expense	$6,679,098	$4,529,039	$942,932	$8,002	$3,354	$977,768	$38,365	$219	$11,181	$438	$8,550
Customer Service Expense											
907 SUPERVISION	$107,651	$85,613	$16,204	$15	$63	$1,848	$73	$0	$11	$0	$8
908 CUSTOMER ASSISTANCE EXPENSES	$106,916	$85,028	$16,093	$15	$63	$1,836	$72	$0	$10	$0	$8
908 CUSTOMER ASSISTANCE EXP-LOAD MGMT	$0										
909 INFORMATIONAL AND INSTRUCTIONA	$0										
909 INFORM AND INSTRUC -LOAD MGMT	$0										
910 MISCELLANEOUS CUSTOMER SERVICE	$20,122	$16,003	$3,029	$3	$12	$345	$14	$0	$2	$0	$2
911 DEMONSTRATION AND SELLING EXP	$0										
912 DEMONSTRATION AND SELLING EXP	$0										
913 WATER HEATER - HEAT PUMP PROGRAM	$0										
915 MDSE-JOBBING-CONTRACT	$0										
916 MISC SALES EXPENSE	$0										
Total Customer Service Labor Expense	$234,689	$186,644	$35,326	$33	$138	$4,029	$158	$1	$23	$1	$18
Sub-Total Labor Exp	$45,220,783	$21,611,056	$5,720,631	$110,159	$256,536	$7,417,960	$2,505,763	$33,856	$311,987	$23,500	$4,079,597
Administrative and General Expense											
920 ADMIN. & GEN. SALARIES-	$10,799,153	$5,160,925	$1,366,141	$26,307	$61,263	$1,771,479	$598,400	$8,085	$74,505	$5,612	$974,247
921 OFFICE SUPPLIES AND EXPENSES	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
922 ADMIN. EXPENSES TRANSFERRED - CREDIT	-$933,756	-$446,243	-$118,124	-$2,275	-$5,297	-$153,172	-$51,741	-$699	-$6,442	-$485	-$84,239
923 OUTSIDE SERVICES EMPLOYED	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
924 PROPERTY INSURANCE	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
925 INJURIES AND DAMAGES - INSURAN	$79,180	$37,840	$10,017	$193	$449	$12,989	$4,388	$59	$546	$41	$7,143
926 EMPLOYEE BENEFITS	$0										
928 REGULATORY COMMISSION FEES	$0										
929 DUPLICATE CHARGES-CR	$0										
930 MISCELLANEOUS GENERAL EXPENSES	$0										
931 RENTS AND LEASES	$0										
932 MAINTENANCE OF GENERAL PLANT	$0										
935 MAINTENANCE OF GENERAL PLANT	$0										
Total Administrative and General Expense	$9,944,577	$4,752,523	$1,258,033	$24,225	$56,415	$1,631,296	$551,046	$7,445	$68,610	$5,168	$897,151
Total Operation and Maintenance Expenses	$55,165,360	$26,363,578	$6,978,665	$134,384	$312,951	$9,049,256	$3,056,810	$41,301	$380,597	$28,668	$4,976,748
Operation and Maintenance Expenses Less Purchase Power	$55,165,360	$26,363,578	$6,978,665	$134,384	$312,951	$9,049,256	$3,056,810	$41,301	$380,597	$28,668	$4,976,748

Kentucky Utilities
Electric Cost of Service Study
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Labor O & M Expenses	LCIT	MPP	MPT	LMPP	LMPT	LITOD	SL	SLDEC	POL	OL
Labor Expenses										
Steam Power Generation Operation Expenses										
500 OPERATION SUPERVISION & ENGINEERING	$85,651	$12,229	$7,489	$9,294	$27,991	$39,324	$4,037	$339	$3,023	$4,625
501 FUEL	$74,334	$9,974	$6,099	$7,906	$23,684	$34,320	$3,925	$330	$2,939	$4,496
502 STEAM EXPENSES	$207,221	$29,959	$18,352	$22,580	$68,074	$95,029	$9,523	$800	$7,131	$10,908
505 ELECTRIC EXPENSES	$139,761	$20,206	$12,378	$15,229	$45,913	$64,093	$6,423	$540	$4,810	$7,357
506 MISC. STEAM POWER EXPENSES	$9,060	$1,310	$802	$987	$2,976	$4,155	$416	$35	$312	$477
507 RENTS	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Steam Power Operation Expenses	$516,027	$73,678	$45,120	$55,996	$168,638	$236,920	$24,325	$2,044	$18,215	$27,863
Steam Power Generation Maintenance Expenses										
510 MAINTENANCE SUPERVISION & ENGINEERING	$136,225	$18,470	$11,296	$14,536	$43,566	$62,839	$7,067	$594	$5,292	$8,095
511 MAINTENANCE OF STRUCTURES	$32,047	$4,633	$2,838	$3,492	$10,528	$14,686	$1,473	$124	$1,103	$1,687
512 MAINTENANCE OF BOILER PLANT	$149,238	$20,025	$12,244	$15,872	$47,551	$68,904	$7,880	$662	$5,901	$9,027
513 MAINTENANCE OF ELECTRIC PLANT	$51,636	$6,929	$4,236	$5,492	$16,452	$23,841	$2,727	$229	$2,042	$3,123
514 MAINTENANCE OF MISC STEAM PLANT	$4,447	$597	$365	$473	$1,417	$2,053	$235	$20	$176	$269
Total Steam Power Generation Maintenance Expense	$373,594	$50,654	$30,980	$39,865	$119,534	$172,333	$19,382	$1,629	$14,513	$22,201
Total Steam Power Generation Expense	$889,620	$124,332	$76,100	$95,862	$288,172	$409,253	$43,706	$3,673	$32,728	$50,064
Hydraulic Power Generation Operation Expenses										
535 OPERATION SUPERVISION & ENGINEERING	$225	$33	$20	$25	$74	$103	$10	$1	$8	$12
536 WATER FOR POWER	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
537 HYDRAULIC EXPENSES	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
538 ELECTRIC EXPENSES	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
539 MISC. HYDRAULIC POWER EXPENSES	$92	$13	$8	$10	$30	$42	$4	$0	$3	$5
540 RENTS	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Hydraulic Power Operation Expenses	$317	$46	$28	$35	$104	$145	$15	$1	$11	$17
Hydraulic Power Generation Maintenance Expenses										
541 MAINTENANCE SUPERVISION & ENGINEERING	$2,577	$354	$217	$276	$829	$1,187	$131	$11	$98	$150
542 MAINTENANCE OF STRUCTURES	$1,207	$175	$107	$132	$397	$554	$55	$5	$42	$64
543 MAINT. OF RESERVES, DAMS, AND WATERWAYS	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
544 MAINTENANCE OF ELECTRIC PLANT	$2,509	$337	$206	$267	$799	$1,158	$132	$11	$99	$152
545 MAINTENANCE OF MISC HYDRAULIC PLANT	$110	$15	$9	$12	$35	$51	$6	$0	$4	$7
Total Hydraulic Power Generation Maint. Expense	$6,403	$880	$539	$686	$2,060	$2,950	$324	$27	$243	$371
Total Hydraulic Power Generation Expense	$6,721	$926	$567	$721	$2,164	$3,096	$339	$28	$254	$388
Other Power Generation Operation Expense										
546 OPERATION SUPERVISION & ENGINEERING	$2,796	$404	$248	$305	$919	$1,282	$128	$11	$98	$147
547 FUEL	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
548 GENERATION EXPENSE	$12,847	$1,857	$1,138	$1,400	$4,220	$5,891	$590	$50	$442	$676
549 MISC OTHER POWER GENERATION	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
550 RENTS	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Other Power Generation Expenses	$15,643	$2,262	$1,385	$1,705	$5,139	$7,174	$719	$60	$538	$823
Other Power Generation Maintenance Expense										
551 MAINTENANCE SUPERVISION & ENGINEERING	$957	$138	$85	$104	$314	$439	$44	$4	$33	$50

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	LCIT	MPP	MPT	LMPP	LMPT	LITOD	SL	SLDEC	POL	OL
552 MAINTENANCE OF STRUCTURES	$2,798	$404	$248	$305	$919	$1,283	$129	$11	$96	$147
553 MAINTENANCE OF GENERATING & ELEC PLANT	$12,198	$1,763	$1,080	$1,329	$4,007	$5,594	$561	$47	$420	$642
554 MAINTENANCE OF MISC OTHER POWER GEN PLT	$2,626	$380	$233	$286	$863	$1,204	$121	$10	$90	$138
Total Other Power Generation Maintenance Expense	$18,578	$2,686	$1,645	$2,024	$6,103	$8,520	$854	$72	$639	$978
Total Other Power Generation Expense	$34,221	$4,947	$3,031	$3,729	$11,242	$15,693	$1,573	$132	$1,178	$1,801
Total Production Expense	$930,562	$130,205	$79,698	$100,311	$301,578	$428,042	$45,618	$3,833	$34,159	$52,254
Purchased Power										
555 PURCHASED POWER										
556 SYSTEM CONTROL AND LOAD DISPATCH	$38,286	$5,535	$3,391	$4,172	$12,577	$17,557	$1,759	$148	$1,317	$2,015
557 OTHER EXPENSES	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Purchased Power Labor	$38,286	$5,535	$3,391	$4,172	$12,577	$17,557	$1,759	$148	$1,317	$2,015
Transmission Labor Expenses										
560 OPERATION SUPERVISION AND ENG	$23,454	$3,391	$2,077	$2,556	$7,705	$10,756	$1,078	$91	$807	$1,235
561 LOAD DISPATCHING	$25,892	$3,743	$2,293	$2,821	$8,506	$11,874	$1,190	$100	$891	$1,363
562 STATION EXPENSES	$5,911	$855	$523	$644	$1,942	$2,711	$272	$23	$203	$311
563 OVERHEAD LINE EXPENSES	$1,058	$153	$94	$115	$348	$485	$49	$4	$36	$56
566 MISC. TRANSMISSION EXPENSES	$6,638	$960	$588	$723	$2,181	$3,044	$305	$26	$228	$349
568 MAINTENACE SUPERVISION AND ENG	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
570 MAINT OF STATION EQUIPMENT	$13,476	$1,948	$1,193	$1,468	$4,427	$6,180	$619	$52	$464	$709
571 MAINT OF OVERHEAD LINES	$3,013	$436	$267	$328	$990	$1,382	$138	$12	$104	$159
572 UNDERGROUND LINES	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
573 MISC PLANT	$1,801	$260	$159	$196	$592	$826	$83	$7	$62	$95
Total Transmission Labor Expenses	$81,243	$11,746	$7,195	$8,853	$26,689	$37,257	$3,734	$314	$2,796	$4,277
Distribution Operation Labor Expense										
580 OPERATION SUPERVISION AND ENGI	$23	$2,082	$28	$1,378	$17	$7,954	$14,231	$2,139	$6,109	$4,012
581 LOAD DISPATCHING	$0	$3,421	$0	$2,347	$0	$13,625	$233	$20	$174	$267
582 STATION EXPENSES	$0	$3,358	$0	$2,303	$0	$13,372	$229	$19	$171	$262
583 OVERHEAD LINE EXPENSES	$7	$6,020	$12	$4,111	$6	$23,849	$10,345	$1,186	$10,230	$8,508
584 UNDERGROUND LINE EXPENSES	$0	$192	$0	$131	$0	$763	$138	$15	$134	$116
585 STREET LIGHTING EXPENSE	$0	$0	$0	$0	$0	$0	$3,813	$737	$610	$900
586 METER EXPENSES	$179	$671	$221	$66	$135	$17	$19,675	$0	$21,512	$0
586 METER EXPENSES - LOAD MANAGEMENT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
587 CUSTOMER INSTALLATIONS EXPENSE	$0	$0	$0	$0	$0	$0	$1,660	$321	$266	$392
588 MISCELLANEOUS DISTRIBUTION EXP	$12	$4,697	$16	$3,195	$9	$18,524	$89,410	$16,567	$20,782	$24,939
589 RENTS										
Total Distribution Operation Labor Expense	$221	$20,443	$278	$13,532	$168	$78,105	$139,733	$21,004	$59,989	$39,393
Distribution Maintenance Labor Expense										
590 MAINTENANCE SUPERVISION AND EN	$0	$18	$0	$12	$0	$69	$35	$5	$28	$24
591 MAINTENANCE OF STRUCTURES	$0	$3	$0	$2	$0	$10	$0	$0	$0	$0
592 MAINTENANCE OF STATION EQUIPME	$0	$2,231	$0	$1,530	$0	$8,883	$152	$13	$114	$174
593 MAINTENANCE OF OVERHEAD LINES	$20	$16,695	$34	$11,399	$17	$66,133	$28,688	$3,289	$28,368	$23,587
594 MAINTENANCE OF UNDERGROUND LIN	$0	$492	$0	$337	$0	$1,954	$352	$40	$343	$297
595 MAINTENANCE OF LINE TRANSFORME	$0	$0	$0	$0	$0	$0	$175	$20	$173	$144
596 MAINTENANCE OF ST LIGHTS & SIG SYSTEMS	$0	$0	$0	$0	$0	$0	$22,850	$4,417	$3,657	$5,396
597 MAINTENANCE OF METERS	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
598 MAINTENANCE OF MISC DISTR PLANT	$0	$0	$0	$0	$0	$1	$3	$0	$1	$1

Kentucky Utilities
Electric Cost of Service Study
(Salaries and Wages)

	LCIT	MPP	MPT	LMPP	LMPT	LITOD	SL	SLDEC	POL	OL
Total Distribution Maintenance Labor Expense	$20	$19,437	$35	$13,280	$17	$77,050	$52,255	$7,783	$32,684	$29,623
Total Distribution Operation and Maintenance Labor Expenses	$241	$39,880	$313	$26,812	$185	$155,154	$191,988	$28,788	$92,672	$69,017
Transmission and Distribution Labor Expenses	$81,485	$51,625	$7,508	$35,665	$26,874	$192,411	$195,722	$29,101	$95,468	$73,294
Production, Transmission and Distribution Labor Expenses	$1,050,332	$187,366	$90,596	$140,148	$341,029	$638,011	$243,099	$33,082	$130,945	$127,563
Customer Accounts Expense										
901 SUPERVISION/CUSTOMER ACCTS	$305	$655	$218	$131	$305	$44	$12,799	$1,643	$5,289	$10,309
902 METER READING EXPENSES	$111	$239	$80	$48	$111	$16	$4,664	$599	$1,927	$3,757
903 RECORDS AND COLLECTION	$1,092	$2,340	$780	$468	$1,092	$156	$45,762	$5,874	$18,910	$36,861
904 UNCOLLECTIBLE ACCOUNTS	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
905 MISC CUST ACCOUNTS	$26	$55	$18	$11	$26	$4	$1,076	$138	$444	$866
Total Customer Accounts Labor Expense	$1,535	$3,288	$1,096	$658	$1,535	$219	$64,300	$8,254	$26,571	$51,793
Customer Service Expense										
907 SUPERVISION	$1	$6	$2	$1	$1	$0	$1,621	$208	$669	$1,305
908 CUSTOMER ASSISTANCE EXPENSES	$1	$6	$2	$1	$1	$0	$1,609	$207	$665	$1,296
908 CUSTOMER ASSISTANCE EXP-LOAD MGMT										
909 INFORMATIONAL AND INSTRUCTIONA										
909 INFORM AND INSTRUC -LOAD MGMT										
910 MISCELLANEOUS CUSTOMER SERVICE	*$0*	*$1*	*$0*	*$0*	*$0*	*$0*	*$303*	*$39*	*$125*	*$244*
911 DEMONSTRATION AND SELLING EXP										
912 DEMONSTRATION AND SELLING EXP										
913 WATER HEATER - HEAT PUMP PROGRAM										
915 MDSE-JOBBING-CONTRACT										
916 MISC SALES EXPENSE										
Total Customer Service Labor Expense	$3	$14	$5	$1	$3	$0	$3,533	$454	$1,460	$2,846
Sub-Total Labor Exp	$1,051,870	$190,668	$91,697	$140,807	$342,567	$638,230	$310,932	$41,790	$158,975	$182,202
Administrative and General Expense										
920 ADMIN. & GEN. SALARIES-	$251,197	$45,533	$21,898	$33,626	$81,808	$152,415	$74,254	$9,980	$37,965	$43,512
921 OFFICE SUPPLIES AND EXPENSES	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
922 ADMIN. EXPENSES TRANSFERRED - CREDIT	-$21,720	-$3,937	-$1,893	-$2,907	-$7,074	-$13,179	-$6,420	-$863	-$3,283	-$3,762
923 OUTSIDE SERVICES EMPLOYED	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
924 PROPERTY INSURANCE	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
925 INJURIES AND DAMAGES - INSURAN	$1,842	$334	$161	$247	$600	$1,118	$544	$73	$278	$319
926 EMPLOYEE BENEFITS										
928 REGULATORY COMMISSION FEES										
929 DUPLICATE CHARGES-CR										
930 MISCELLANEOUS GENERAL EXPENSES										
931 RENTS AND LEASES										
932 MAINTENANCE OF GENERAL PLANT										
935 MAINTENANCE OF GENERAL PLANT										
Total Administrative and General Expense	$231,318	$41,930	$20,165	$30,965	$75,334	$140,354	$68,378	$9,190	$34,961	$40,068
Total Operation and Maintenance Expenses	$1,283,189	$232,598	$111,862	$171,772	$417,902	$778,585	$379,310	$50,980	$193,936	$222,270
Operation and Maintenance Expenses Less Purchase Power	$1,283,189	$232,598	$111,862	$171,772	$417,902	$778,585	$379,310	$50,980	$193,936	$222,270

Kentucky Utilities
Electric Cost of Service Study
(Revenues)

	Total	Rate RS	GSS	GSP	AES	LPS	LPP	LPT	STODS	STODP
1 REVENUE										
Sales	$1,112,461,756	$419,658,059	$136,859,016	$3,021,554	$7,663,577	$217,223,150	$83,319,633	$1,313,122	$9,082,579	$729,069
Accrued Revenues	-$17,682,129	-$6,670,295	-$2,175,319	-$48,026	-$121,809	-$3,452,674	-$1,324,332	-$20,872	-$144,364	-$11,588
Intercompany Sales	$41,161,612	$14,421,791	$4,038,600	$93,972	$292,821	$8,427,406	$3,492,460	$54,600	$420,158	$34,066
Off-System Sales	$6,327,778	$1,802,945	$644,289	$1,581	$35,611	$1,420,044	$604,313	$8,396	$71,335	$5,788
Brokered Sales	-$90,748	-$31,795	-$8,904	-$207	-$646	-$18,580	-$7,700	-$120	-$926	-$75
Redundant Capacity	$10,854	$0	$0	$0	$0	$7,793	$3,061	$0	$0	$0
Misc Service Revenues	$1,578,059	$760,286	$343,576	$7,585	$4,405	$305,527	$117,190	$1,847	$19,622	$1,575
Rent From Electric Property	$1,994,812	$282,465	$339,262	$7,490	$3,710	$506,649	$194,334	$3,063	$16,405	$1,317
Other Electric Revenue	$2,585,939	$1,383,113	$309,712	$7,434	$15,161	$340,842	$128,036	$2,206	$15,153	$1,215
Unbilled Revenue	$6,878,000	$2,594,613	$846,156	$18,681	$47,381	$1,343,022	$515,139	$8,119	$56,155	$4,508
Merger Surcredit Amortization	-$1,069,892	$0	$0	$0	$0	-$28,815	-$90,782	$0	$0	$0
TOTAL REVENUE	**$1,154,156,041**	**$434,201,182**	**$141,196,389**	**$3,110,064**	**$7,940,212**	**$226,074,364**	**$86,951,352**	**$1,370,360**	**$9,536,117**	**$765,874**

Kentucky Utilities
Electric Cost of Service Study
(Revenues)

	LCIP	LCIT	MPP	MPT	LMPP	LMPT	LITOD	SL	SLDEC	POL	OL
1 REVENUE											
Sales	$129,712,936	$34,065,000	$6,647,734	$3,858,665	$4,738,074	$13,387,914	$22,399,700	$7,312,068	$1,378,192	$4,076,500	$6,015,214
Accrued Revenues	-$2,061,735	-$541,449	-$105,663	-$61,332	-$75,310	-$212,795	-$356,034	-$116,222	-$21,906	-$64,794	-$95,609
Intercompany Sales	$5,904,879	$1,761,308	$236,338	$144,505	$187,324	$561,190	$813,204	$93,003	$7,815	$69,642	$106,532
Off-System Sales	$1,029,309	$310,679	$33,209	$21,467	$29,817	$96,202	$152,624	$20,202	$1,698	$15,128	$23,141
Brokered Sales	-$13,018	-$3,883	-$521	-$319	-$413	-$1,237	-$1,793	-$205	-$17	-$154	-$235
Redundant Capacity	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Misc Service Revenues	$12,234	$3,213	$200	$0	$0	$339	$458	$0	$0	$0	$0
Rent From Electric Property	$378,299	$99,348	$33,370	$0	$0	$57,364	$71,737	$0	$0	$0	$0
Other Electric Revenue	$206,683	$57,050	$11,108	$6,252	$7,639	$20,376	$29,333	$17,762	$2,478	$9,635	$14,751
Unbilled Revenue	$801,974	$210,613	$41,101	$23,857	$29,294	$82,773	$138,490	$45,208	$8,521	$25,204	$37,190
Merger Surcredit Amortization	-$797,953	-$152,342	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL REVENUE	$135,173,608	$35,809,536	$6,896,875	$3,993,096	$4,916,425	$13,992,126	$23,247,719	$7,371,816	$1,376,780	$4,131,161	$6,100,984

Kentucky Utilities
Electric Cost of Service Study
(Allocator Amounts)

Alloc No.	Allocator Description	Total	Rate RS	GSS	GSP	AES	LPS	LPP	LPT	STODS	STODP
1	Energy (Loss Adjusted)	$20,156,276,125	$7,062,152,956	$1,977,646,848	$46,016,783	$143,390,395	$4,126,784,782	$1,710,209,770	$26,736,679	$205,745,622	$16,681,560
2	Energy	$18,783,418,257	$6,497,809,251	$1,819,611,111	$43,720,684	$131,931,925	$3,797,009,283	$1,624,875,433	$26,100,266	$189,304,284	$15,849,200
3	Customers (Monthly Bills)	$7,996,703	$4,958,111	$938,420	$872	$3,668	$107,045	$4,202	$24	$612	$24
4	Average Customers (Bills/12)	$666,393	$413,176	$78,202	$73	$306	$8,920	$350	$2	$51	$2
5	Average Customers (Lighting = Lights)	$666,393	$413,176	$78,202	$73	$306	$8,920	$350	$2	$51	$2
6	Weighted Average Customers (Lighting =9 Lights per Cust)	$609,322	$413,176	$88,022	$730	$306	$89,200	$3,500	$20	$1,020	$40
7	Street Lighting	$69,869,338	$0	$0	$0	$0	$0	$0	$0	$0	$0
8	Average Customers	$666,393	$413,176	$78,202	$73	$306	$8,920	$350	$2	$51	$2
9	Average Customers (Lighting = 9 Lights per Cust)	$519,535	$413,176	$78,202	$73	$306	$8,920	$350	$2	$51	$2
10	Average Secondary Customers	$519,012	$413,176	$78,202	$0	$306	$8,920	$0	$0	$51	$0
11	Average Primary Customers	$519,536	$413,176	$78,202	$73	$306	$8,920	$350	$2	$51	$2
12	Year End Customers	$502,777	$414,418	$78,768	$72	$310	$8,707	$347	$2	$51	$2
13	Year End Customers (Lighting = Lights)	$708,973	$414,418	$78,768	$72	$310	$8,707	$347	$2	$51	$2
14	Weighted Year End Customers (Lighting =9 Lights per Cust)	$612,466	$414,418	$86,645	$720	$310	$87,070	$3,470	$20	$1,020	$40
15	Street Lighting	$52,453,968	$0	$0	$0	$0	$0	$0	$0	$0	$0
16	Year End Customers	$708,973	$414,418	$78,768	$72	$310	$8,707	$347	$2	$51	$2
17	Year End Customers (Lighting = 9 Lights per Cust)	$525,687	$414,418	$78,768	$72	$310	$8,707	$347	$2	$51	$2
18	Year End Secondary Customers	$525,167	$414,418	$78,768	$0	$310	$8,707	$0	$0	$51	$2
19	Year End Primary Customers	$525,688	$414,418	$78,768	$72	$310	$8,707	$347	$2	$51	$2
20	Maximum Class Non-Coincident Peak Demands	$4,667,350	$2,277,441	$469,138	$26,268	$47,098	$719,439	$282,559	$5,128	$31,402	$2,255
21	Primary Distribution Plant -- Average Number of Customers	1.00000	0.79528	0.15052	0.00014	0.00059	0.01717	0.00067	0.00000	0.00010	0.00000
22	Customer Services -- Weighted cost of Services	1.00000	0.58798	0.11090	0.00000	0.00625	0.29477	0.00000	0.00000	0.00010	0.00000
23	Meter Costs -- Weighted Cost of Meters	1.00000	0.62251	0.27464	0.00067	0.00213	0.07698	0.00318	0.00002	0.00024	0.00001
24	Lighting Systems -- Lighting Customers	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
25	Meter Reading and Billing -- Weighted Cost	1.00000	0.67809	0.14118	0.00120	0.00050	0.14639	0.00574	0.00003	0.00167	0.00007
26	Marketing/Economic Development	1.00000	0.79528	0.15052	0.00014	0.00059	0.01717	0.00067	0.00000	0.00010	0.00000
27	Rev	1112462089.000	419658185.000	136859057.000	3021555.000	7663579.000	217223215.000	83319658.000	1313122.000	9082582.000	729069.000
28	Maximum Class Demands (Primary)	$4,471,090	$2,277,441	$469,138	$26,268	$47,098	$719,439	$282,559	$0	$31,402	$2,255
29	Sum of the Individual Customer Demands (Secondary)	$8,070,265	$4,909,823	$2,475,479	$0	$49,473	$595,762	$0	$0	$33,223	$0
30	Summer Peak Period Demand Allocator	$3,555,506	$1,479,783	$393,532	$21,700	$24,220	$680,416	$257,634	$4,735	$33,912	$2,075
31	Winter Peak Period Demand Allocator	$3,594,667	$1,896,227	$277,905	$23,766	$44,306	$529,267	$205,311	$4,751	$25,365	$2,500
32	Base Demand Allocator	$2,294,658	$803,979	$225,142	$5,239	$16,324	$469,807	$194,696	$3,044	$23,423	$1,899
33	Production Residual Winter Demand Allocator	$2,279,717	$803,979	$225,142	$5,239	$16,324	$469,807	$194,696	$3,044	$23,423	$1,899
34	Production Winter Demand Allocator	$1	$1	$0	$0	$0	$0	$0	$0	$0	$0
35	Production Residual Summer Demand Allocator	$3,555,506	$1,479,783	$393,532	$21,700	$24,220	$680,416	$257,634	$4,735	$33,912	$2,075
36	Production Summer Demand Allocator	$1	$0	$0	$0	$0	$0	$0	$0	$0	$0
37	Production Residual Summer Demand Allocator	$3,555,506	$1,479,783	$393,532	$21,700	$24,220	$680,416	$257,634	$4,735	$33,912	$2,075
38	Production Summer Demand Total	$18,189,248	$7,570,271	$2,013,230	$111,012	$123,905	$3,480,871	$1,318,003	$24,223	$173,486	$10,615
39	Distribution O&M	$916,133,794	$627,091,863	$148,521,175	$1,156,512	$3,689,346	$73,324,792	$12,186,074	$1,189	$1,988,306	$97,509
40	Total Other Revenue allocator	$6,158,810	$3,294,095	$737,627	$17,706	$36,109	$811,767	$304,936	$5,254	$36,089	$2,894
41	Customer Specific Assignment	$0		$0	$0	$0	$0	$0	$0	$0	$0
42	Misc Service Revenue Allocator	$3,260,775	$1,570,995	$709,938	$15,674	$9,102	$631,317	$242,152	$3,816	$40,546	$3,255
43	Off-System Sales Allocator	$6,327,778	$1,802,945	$644,289	$1,581	$35,611	$1,420,044	$604,313	$8,396	$71,335	$5,768
44	Interruptible Credit Allocator	$1,285,910,033	$621,329,040	$116,503,314	$8,241,533	$13,026,103	$211,932,756	$81,303,247	$1,704,712	$10,344,505	$837,030
45	Operation and Maintenance Less Fuel	$180,545,747	$101,747,472	$22,663,362	$553,014	$1,013,169	$23,812,729	$7,145,379	$118,563	$924,581	$70,491
46	Base Rate Revenue	$958,043,947	$364,691,143	$121,479,709	$2,654,163	$6,648,873	$186,103,586	$70,244,702	$1,110,048	$7,580,016	$607,081
47	VDT Revenue	-$3,405,552	-$1,281,117	-$416,427	-$9,403	-$23,364	-$660,193	-$253,206	-$3,988	-$27,621	-$2,222
48	Merger Surcredit Revenue	-$17,498,536	-$6,931,759	-$2,258,368	-$50,423	-$125,127	-$3,549,075	-$1,260,029	-$21,533	-$149,681	-$11,935
49	Remove ECR Revenues	$54,342,068	$20,625,999	$6,655,712	$150,004	$375,761	$10,481,169	$4,017,666	$63,713	$439,535	$35,498
50	Customer Specific Assignment	$0		$0	$0	$0	$0	$0	$0	$0	$0
51	Gross Production Plant	$1,873,146,664	$677,526,459	$187,838,546	$5,508,604	$13,228,040	$379,194,514	$154,936,348	$2,486,371	$18,904,177	$1,471,531
52	Gross Transmission Plant	$417,885,239	$151,151,168	$41,905,397	$1,228,929	$2,951,078	$84,595,506	$34,565,159	$554,691	$4,217,383	$328,288
53	Gross Distribution Plant	$1,017,723,772	$582,948,784	$166,953,311	$2,108,793	$5,832,645	$104,709,311	$22,327,858	$1,628	$3,437,488	$177,340
54	Total Prod.,Trans., Distrib Plant	$3,308,755,675	$1,411,626,412	$396,697,255	$8,846,326	$22,011,764	$568,499,332	$211,829,366	$3,042,690	$26,559,048	$1,977,158
55	Dist. Overhead Lines Gross Plant	$383,731,334	$241,823,501	$55,745,327	$1,131,887	$2,352,620	$36,221,807	$12,075,466	$468	$1,525,178	$96,296
56	Gross Intangible Plant	$22,416,263	$9,563,540	$2,687,560	$59,932	$149,126	$3,851,491	$1,435,110	$20,614	$179,933	$13,395
57	Gross Total Plant in Service	$3,419,830,880	$1,459,014,829	$410,014,415	$9,143,298	$22,750,700	$587,583,902	$218,940,495	$3,144,833	$27,450,637	$2,043,531
58	Dist. Underground Lines Gross Plant	$86,568,726	$50,231,927	$12,453,078	$333,141	$682,631	$10,305,035	$3,571,977	$54	$450,357	$28,498
59	Gross General Plant	$88,658,922	$37,824,877	$10,629,600	$237,039	$589,811	$15,233,079	$5,676,020	$81,530	$711,656	$52,978
60	Labor Accts 501-507	$10,465,257	$3,772,879	$1,047,699	$29,693	$74,137	$2,126,605	$870,988	$13,916	$106,020	$8,310
61	Labor Accts 511-514	$5,585,749	$1,966,004	$549,754	$13,270	$39,696	$1,141,810	$472,257	$7,410	$56,926	$4,590
62	Labor Accts 536-540	$2,262	$818	$227	$7	$16	$458	$187	$3	$23	$2
63	Labor Accts 542-545	$90,886	$32,173	$8,980	$227	$645	$18,536	$7,647	$121	$924	$74
64	Labor Accts 581-588	$7,031,202	$4,181,905	$1,335,601	$16,237	$36,689	$704,876	$163,779	$49	$20,518	$1,265
65	Labor Accts 591-598	$22,328,441	$13,905,201	$3,213,522	$68,402	$141,194	$2,170,049	$730,306	$26	$91,755	$5,824
66	Labor Accts 500-916	$45,220,783	$21,611,056	$5,720,631	$110,159	$256,536	$7,417,960	$2,505,763	$33,856	$311,987	$23,500
67	O&M less Purchased Power	$632,258,594	$249,352,560	$67,753,145	$1,469,480	$4,182,774	$120,295,896	$47,384,462	$717,682	$5,750,178	$457,840

Kentucky Utilities
Electric Cost of Service Study
(Allocator Amounts)

Alloc No.	Allocator Description	Total	Rate RS	GSS	GSP	AES	LPS	LPP	LPT	STODS	STODP
68	Dist. Lines Gross Plant	$470,320,060	$292,055,429	$68,198,405	$1,465,028	$3,035,251	$46,526,842	$15,647,443	$521	$1,975,535	$124,795
69	Rate Base	$2,634,973,710	$1,090,894,641	$305,708,873	$7,140,789	$17,717,717	$468,634,814	$178,341,854	$2,632,364	$22,206,711	$1,672,966
70	Gross Transformer Plant	$235,411,371	$154,474,157	$62,449,760	$0	$1,098,183	$13,814,235	$0	$0	$718,836	$237
71	Dpreciation Expense	$109,736,123	$46,776,559	$13,144,361	$293,559	$730,284	$18,873,622	$7,037,078	$101,167	$882,131	$65,691
72	Total Labor	$55,165,360	$26,363,578	$6,978,665	$134,384	$312,951	$9,049,256	$3,056,810	$41,301	$380,597	$28,668
73	Distribution O&M	$38,758,632	$23,713,959	$6,460,794	$103,073	$221,788	$3,779,138	$1,074,727	$155	$135,286	$8,461
74	Sales Revenue	$1,112,461,756	$419,658,059	$136,859,016	$3,021,554	$7,663,577	$217,223,150	$83,319,633	$1,313,122	$9,082,579	$729,069
75	Distribution Poles, Lines, Transform & Services	$783,761,532	$492,409,491	$139,302,015	$1,465,028	$4,620,810	$83,342,089	$15,647,443	$521	$2,702,330	$125,032
76											
77											

Kentucky Utilities
Electric Cost of Service Study
(Allocator Amounts)

Alloc No.	Allocator Description	LCIP	LCIT	MPP	MPT	LMPP	LMPT	LITOD	SL	SLDEC	POL	OL
1	Energy (Loss Adjusted)	$2,891,538,085	$862,488,183	$115,731,325	$70,762,356	$91,730,180	$274,807,237	$398,214,663	$45,542,217	$3,826,828	$34,102,592	$52,167,064
2	Energy	$2,747,259,009	$841,958,377	$109,956,679	$69,078,000	$87,153,119	$268,266,000	$388,735,959	$41,902,893	$3,521,022	$31,377,420	$47,998,342
3	Customers (Monthly Bills)	$466	$79	$364	$123	$39	$82	$12	$844,691	$108,454	$348,991	$680,424
4	Average Customers (Bills/12)	$39	$7	$30	$10	$3	$7	$1	$70,391	$9,038	$29,083	$56,702
5	Average Customers (Lighting = Lights)	$39	$7	$30	$10	$3	$7	$1	$70,391	$9,038	$29,083	$56,702
6	Weighted Average Customers (Lighting =9 Lights per Cust)	$780	$140	$300	$100	$60	$140	$20	$5,866	$753	$2,424	$4,725
7	Street Lighting	$0	$0	$0	$0	$0	$0	$0	$43,956,496	$8,497,472	$7,034,856	$10,380,514
8	Average Customers	$39	$7	$30	$10	$3	$7	$1	$70,391	$9,038	$29,083	$56,702
9	Average Customers (Lighting = 9 Lights per Cust)	$39	$7	$30	$10	$3	$7	$1	$7,821	$1,004	$3,231	$6,300
10	Average Secondary Customers	$0	$0	$0	$0	$0	$0	$0	$7,821	$1,004	$3,231	$6,300
11	Average Primary Customers	$39	$7	$30	$10	$3	$7	$1	$7,821	$1,004	$3,231	$6,300
12	Year End Customers	$40	$7	$31	$12	$3	$6	$1	$0	$0	$0	$0
13	Year End Customers (Lighting = Lights)	$40	$7	$31	$12	$3	$8	$1	$70,537	$8,186	$70,537	$56,936
14	Weighted Year End Customers (Lighting =9 Lights per Cust)	$800	$140	$310	$120	$60	$120	$20	$5,878	$682	$5,878	$4,745
15	Street Lighting	$0	$0	$0	$0	$0	$0	$0	$33,000,064	$6,379,424	$5,281,374	$7,793,106
16	Year End Customers	$40	$7	$31	$12	$3	$6	$1	$70,537	$8,186	$70,537	$56,936
17	Year End Customers (Lighting = 9 Lights per Cust)	$40	$7	$31	$12	$3	$6	$1	$7,837	$910	$7,837	$6,326
18	Year End Secondary Customers	$0	$0	$0	$0	$0	$0	$0	$7,837	$910	$7,837	$6,326
19	Year End Primary Customers	$40	$7	$31	$12	$3	$6	$1	$7,837	$910	$7,837	$6,326
20	Maximum Class Non-Coincident Peak Demands	$427,099	$121,476	$32,089	$17,176	$22,011	$52,480	$127,786	$2,184	$184	$1,635	$2,502
21	Primary Distribution Plant -- Average Number of Customers	0.00008	0.00001	0.00006	0.00002	0.00001	0.00001	0.00000	0.01505	0.00193	0.00622	0.01214
22	Customer Services -- Weighted cost of Services	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
23	Meter Costs -- Weighted Cost of Meters	0.00036	0.00007	0.00027	0.00009	0.00003	0.00006	0.00001	0.00800	0.00000	0.00875	0.00000
24	Lighting Systems -- Lighting Customers	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.62912	0.12162	0.10069	0.14857
25	Meter Reading and Billing -- Weighted Cost	0.00128	0.00023	0.00049	0.00016	0.00010	0.00023	0.00003	0.00964	0.00124	0.00398	0.00775
26	Marketing/Economic Development	0.00008	0.00001	0.00006	0.00002	0.00001	0.00001	0.00000	0.01505	0.00193	0.00623	0.01213
27	Rev	129712975.000	34065011.000	6647736.000	3858666.000	4738075.000	13387918.000	22399707.000	7312070.000	1378192.000	4076501.000	6015216.000
28	Maximum Class Demands (Primary)	$427,099	$0	$32,089	$0	$22,011	$0	$127,786	$2,184	$184	$1,635	$2,502
29	Sum of the Individual Customer Demands (Secondary)	$0	$0	$0	$0	$0	$0	$0	$2,184	$184	$1,635	$2,502
30	Summer Peak Period Demand Allocator	$406,246	$108,974	$23,354	$14,419	$13,783	$43,030	$47,693	$0	$0	$0	$0
31	Winter Peak Period Demand Allocator	$352,268	$106,233	$24,657	$12,758	$16,011	$33,629	$33,210	$2,184	$184	$1,635	$2,502
32	Base Demand Allocator	$329,182	$98,189	$13,175	$8,056	$10,443	$31,285	$45,334	$5,185	$436	$3,882	$5,939
33	Production Residual Winter Demand Allocator	$329,182	$98,189	$13,175	$8,056	$10,443	$31,285	$45,334	$5,185	$436	$3,882	$5,939
34	**Production Winter Demand Allocator**	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
35	Production Residual Summer Demand Allocator	$406,246	$108,974	$23,354	$14,419	$13,783	$43,030	$47,693	$0	$0	$0	$0
36	Production Summer Demand Allocator	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
37	Production Residual Summer Demand Allocator	$406,246	$108,974	$23,354	$14,419	$13,783	$43,030	$47,693	$0	$0	$0	$0
38	Production Summer Demand Total	$2,078,272	$557,489	$119,474	$73,765	$70,511	$220,133	$243,988	$0	$0	$0	$0
39	Distribution O&M	$18,131,624	$4,162	$1,378,920	$7,136	$934,991	$3,568	$5,418,374	$7,591,249	$876,755	$7,558,078	$6,172,171
40	Total Other Revenue allocator	$492,246	$135,872	$26,455	$14,891	$18,194	$48,529	$69,861	$42,302	$5,902	$22,948	$35,133
41	Customer Specific Assignment	$0	$0	$0	$0			$0	$0	$0		
42	Misc Service Revenue Allocator	$25,280	$6,639	$414	$0	$0	$701	$946	$0	$0	$0	$0
43	Off-System Sales Allocator	$1,029,309	$310,679	$33,209	$21,467	$29,817	$96,202	$152,624	$20,202	$1,698	$15,128	$23,141
44	Interruptible Credit Allocator	$134,342,697	$38,563,883	$8,671,502	$4,822,695	$5,431,805	$13,436,745	$14,018,131	$470,179	$39,508	$352,076	$538,574
45	Operation and Maintenance Less Fuel	$11,502,465	$3,042,676	$664,235	$330,812	$441,152	$1,028,993	$1,544,680	$1,981,562	$306,385	$642,981	$1,013,046
46	Base Rate Revenue	$107,887,035	$32,985,640	$5,800,666	$3,326,359	$4,055,754	$11,352,111	$14,042,852	$6,845,722	$1,321,287	$3,767,361	$5,539,838
47	VDT Revenue	-$394,429	-$120,177	-$20,228	-$11,701	-$14,392	-$40,804	-$68,105	-$22,193	-$4,259	-$12,408	-$19,315
48	Merger Surcredit Revenue	-$1,535,989	-$460,770	-$108,485	-$63,911	-$77,434	-$218,899	-$365,961	-$120,138	-$23,165	-$66,864	-$98,990
49	Remove ECR Revenues	$6,234,214	$1,899,790	$322,307	$185,612	$226,784	$653,513	$1,074,397	$351,684	$62,946	$196,490	$289,273
50	Customer Specific Assignment	$0	$0	$0	$0			$0	$0	$0		
51	Gross Production Plant	$259,296,185	$76,236,001	$11,021,707	$6,751,731	$8,307,055	$25,044,177	$34,960,746	$3,503,492	$284,392	$2,623,459	$4,013,131
52	Gross Transmission Plant	$57,847,071	$17,007,691	$2,456,862	$1,506,261	$1,853,243	$5,587,172	$7,799,485	$781,603	$65,677	$585,274	$895,300
53	Gross Distribution Plant	$33,350,049	$6,313	$2,528,081	$8,662	$1,719,488	$4,946	$9,969,089	$48,118,361	$8,915,935	$11,184,273	$13,421,416
54	Total Prod.,Trans., Distrib Plant	$350,493,305	$93,250,004	$16,008,651	$8,266,654	$11,879,785	$30,636,295	$52,729,320	$52,403,456	$9,276,003	$14,393,006	$18,329,846
55	Dist. Overhead Lines Gross Plant	$18,139,286	$1,636	$1,369,393	$2,805	$935,047	$1,403	$5,424,625	$2,353,163	$269,748	$2,326,942	$1,934,737
56	Gross Intangible Plant	$2,374,535	$631,754	$108,456	$56,005	$80,484	$207,556	$357,233	$355,025	$62,843	$97,510	$124,182
57	Gross Total Plant in Service	$362,259,395	$96,380,415	$16,546,062	$8,544,166	$12,278,591	$31,664,756	$54,499,447	$54,162,644	$9,587,400	$14,878,181	$18,945,181
58	Dist. Underground Lines Gross Plant	$5,386,113	$189	$405,427	$324	$277,604	$162	$1,611,204	$290,533	$32,724	$282,745	$245,001
59	Gross General Plant	$9,391,554	$2,498,657	$428,956	$221,507	$318,322	$820,907	$1,412,895	$1,404,163	$248,553	$385,664	$491,153
60	Labor Accts 501-507	$1,460,189	$430,376	$61,449	$37,631	$46,702	$140,647	$197,596	$20,287	$1,705	$15,191	$23,238
61	Labor Accts 511-514	$797,350	$237,368	$32,164	$19,684	$25,329	$75,948	$109,494	$12,314	$1,035	$9,221	$14,106
62	Labor Accts 536-540	$313	$92	$13	$8	$10	$30	$42	$4	$0	$3	$5
63	Labor Accts 542-545	$12,886	$3,826	$526	$322	$410	$1,231	$1,763	$194	$16	$145	$222
64	Labor Accts 581-588	$235,390	$199	$18,361	$250	$12,154	$151	$70,150	$125,502	$18,865	$53,879	$35,382
65	Labor Accts 591-598	$1,097,682	$90	$82,830	$154	$56,582	$77	$328,281	$165,405	$21,740	$133,978	$115,344
66	Labor Accts 500-916	$4,079,597	$1,051,870	$190,668	$91,697	$140,807	$342,567	$638,230	$310,932	$41,780	$158,976	$182,202
67	O&M less Purchased Power	$79,420,243	$22,953,640	$3,302,590	$1,909,488	$2,570,247	$7,350,135	$11,271,913	$2,405,065	$275,920	$1,453,128	$1,982,205